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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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**INDIANA UTILITY
REGULATORY COMMISSION**

**PETITION OF NORTHERN INDIANA)
PUBLIC SERVICE COMPANY FOR)
APPROVAL OF A NEW SCHEDULE OF)
RATES AND CHARGES FOR ELECTRIC)
UTILITY SERVICE, FOR APPROVAL OF)
REVISED DEPRECIATION RATES, FOR)
APPROVAL OF TRACKING MECHANISMS)
PURSUANT TO IND. CODE § 8-1-2-42(a),)
FOR APPROVAL OF REVISED RULES AND)
REGULATIONS APPLICABLE TO)
ELECTRIC UTILITY SERVICE, AND FOR)
DECLINATION OF JURISDICTION AND)
APPROVAL OF AN ALTERNATIVE)
REGULATORY PLAN PURSUANT TO IND.)
CODE § 8-1-2.5-1 *ET SEQ.*)**

CAUSE NO. 43526

PETITIONER'S SUBMISSION OF REVISED AND SUPPLEMENTAL TESTIMONY

Volume 1 of 2

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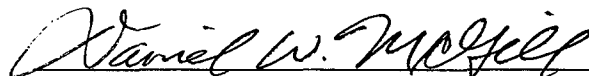
PETITIONER'S SUBMISSION OF REVISED AND SUPPLEMENTAL TESTIMONY

In its Agreed Motion to Continue Beginning of Evidentiary Hearing, Petitioner Northern Indiana Public Service Company ("NIPSCO") advised the Commission that pursuant to a *Stipulation and Settlement Agreement* submitted in Cause No. 43396-S1 and by agreement of the parties to this proceeding, NIPSCO would file Revised and Supplemental Testimony on Friday, December 19, 2008, to address the incorporation of the Sugar Creek generating facility into the evidence in this case and to address correction of an error inadvertently incorporated into NIPSCO's case-in-chief.

As discussed in the motion, NIPSCO hereby submits Revised and Supplemental Direct Testimony of its witnesses as shown below. In addition to providing a clean copy of the revised pages of the Revised Direct Testimony, NIPSCO is providing a black-lined copy showing the revisions (where practical). Supplemental Direct Testimony is being provided as a clean copy.

1. Eileen O'Neill Odum. Tab 1 contains a black-lined and a clean copy of the revised pages to Petitioner's Exhibit EOO-1.
2. Linda E. Miller Testimony. Tab 2 contains a black-lined and a clean copy of the revised pages to Petitioner's Exhibit LEM-1, including a clean copy of Petitioner's Exhibit LEM-2 (Revised) through LEM-5 (Revised).
3. Robert D. Campbell. Tab 3 contains a clean copy of the Verified Supplemental Direct Testimony of Robert D. Campbell, Petitioner's Exhibit RDC-S1.
4. John M. O'Brien. Tab 4 contains a black-lined and a clean copy of the revised pages to Petitioner's Exhibit JMO-1, including a clean copy of Petitioner's Exhibit JMO-2.
5. Phillip W. Pack. Tab 5 contains a black-lined and a clean copy of the revised pages to Petitioner's Exhibit PWP-1, including a clean copy of Petitioner's Exhibit PWP-3 (Revised).
6. Frank A. Shambo. Tab 6 contains a black-lined and a clean copy of the revised pages to Petitioner's Exhibit FAS-1.
7. Frank A. Shambo. Tab 7 contains a clean copy of the Verified Supplemental Direct Testimony of Frank A. Shambo, Petitioner's Exhibit FAS-S1.
8. Robert D. Greneman. Tab 8 contains a black-lined and a clean copy of the revised pages to Petitioner's Exhibit RDG-1, including Petitioner's Exhibit RDG-2 (Revised) and RDG-4 (Revised).
9. Robert D. Greneman. Tab 9 contains a clean copy of the Verified Supplemental Direct Testimony of Robert D. Greneman, Petitioner's Exhibit RDG-S1.
10. Curt A. Westerhausen. Tab 10 contains a clean copy of the Verified Supplemental Direct Testimony of Curt A. Westerhausen, Petitioner's Exhibit CAW-S1, including Petitioner's Exhibit CAW-S2.
11. Bradley K. Sweet. Tab 11 contains a black-lined and a clean copy of the revised pages to Petitioner's Exhibit BKS-1.

Respectfully Submitted,



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Certificate of Service

I hereby certify that a copy of the foregoing was served this 19th day of December, 2008

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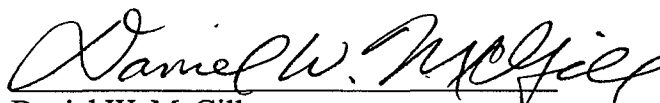
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Daniel W. McGill

1 **IV. OVERVIEW OF NIPSCO'S PROPOSAL**

2 **Q16. Please summarize NIPSCO's proposed changes in base rates.**

3 A16. NIPSCO seeks an ~~two-step~~ increase in rates over those approved by the
4 Commission in its last general rate proceeding, Cause No. 38045. The increase in
5 gross margin (revenues less fuel, purchased power and associated taxes) proposed
6 ~~in the first step is approximately \$85,744,681, which is in contrast to the~~
7 ~~combined amount of approximately \$104 million previously proposed in Step~~
8 ~~One and Step Two 23,983,452. This increase~~ The first step captures operational
9 expenses as of the close of the calendar year 2007 test year, as adjusted for fixed,
10 known and measurable changes, ~~and~~. The proposed second step accounts for the
11 addition of the Sugar Creek Facility to NIPSCO's rate base, ~~upon its dispatch into~~
12 the Midwest ISO. The second step will enable NIPSCO to recover capital costs
13 and the operating expenses relating to the Sugar Creek. The proposed second step
14 will increase revenues by an additional \$80,723,642.

15 **Q17. Please identify the witnesses presenting direct testimony for the Company.**

16 A17. NIPSCO's case-in-chief consists of testimony and exhibits from 22 witnesses.
17 Table 2 below identifies each witness and the major topics addressed in his or her
18 testimony.

19 Table 2 - Table of Witnesses.

Witness	Major Topics
Robert C. Skaggs, Jr. President and CEO NiSource Inc.	Overview of NiSource and its corporate structure NiSource Strategic Plan Access to capital markets

Revised

Witness	Major Topics
John M. O'Brien Assistant Controller of Taxes NiSource Corporate Services	NIPSCO's federal and state income tax expense adjustments Adjustments for taxes other than income
Philip W. Pack Manager, Major Products & Resource Development NIPSCO	NIPSCO's generation fleet Demolition of certain generation units Generation O&M expense adjustment for contract labor Amendments to NIPSCO's environmental cost recovery mechanisms
Timothy A. Dehring Senior Vice President, Energy Delivery NiSource Corporate Services	Transmission system operations Implementation of FERC Seven-Factor Test Distribution system operations Planned investment in work management technologies New electric safety programs Impact of employee retirements to the transmission and distribution operations segment
Frank A. Shambo Vice President, Regulatory and Legislative Affairs NiSource Corporate Services	Background of NIPSCO's existing rates Certain proforma revenue adjustments Overview of rate design principles New rate design/tariff policy Step Two rate proposal associated with the Sugar Creek Generating Facility Rationale for NIPSCO's proposed Reliability Adjustment tracking mechanism Overview of tariff simplification effort NIPSCO's future rate issues
Robert D. Greneman, P.E. Stone & Webster Management Consultants, Inc.	NIPSCO's cost of service study Development of NIPSCO's proposed rate structure Results of application of FERC Seven-Factor Test
Curt A. Westerhausen Manager, Rates and Contracts NiSource Corporate Services	Tariff revisions, including the Company's comprehensive review and modification of tariff

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4 last general rate proceeding, Cause No. 38045. The increase in gross margin
5 (revenues less fuel, purchased power and associated taxes) proposed is
6 approximately \$85,744,681, which is in contrast to the combined amount of
7 approximately \$104 million previously proposed in Step One and Step Two. This
8 increase captures operational expenses as of the close of the calendar year 2007
9 test year, as adjusted for fixed, known and measurable changes, and the addition
10 of the Sugar Creek Facility to NIPSCO's rate base.

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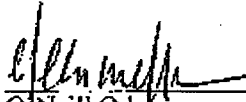
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Curt A. Westerhausen Manager, Rates and Contracts NiSource Corporate Services	Tariff revisions, including the Company's comprehensive review and modification of tariff

VERIFICATION

I, Eileen O'Neill Odum, President of Northern Indiana Public Service Company,
affirm under penalties of perjury that the foregoing representations are true and correct to
the best of my knowledge, information and belief.


Eileen O'Neill Odum

Date: December 19, 2008

VERIFIED DIRECT TESTIMONY OF LINDA E. MILLER

Q1. Please state your name, business address and job title.

A1. My name is Linda E. Miller. My business address is 801 East 86th Avenue, Merrillville, Indiana 46410. I am employed by NiSource Corporate Services ("NCS"), which is a subsidiary of NiSource Inc. ("NiSource"). My current position is Executive Director of Rates and Regulatory Finance for the Northern Indiana Energy business unit, which is comprised of Northern Indiana Public Service Company ("NIPSCO" or the "Company"), Northern Indiana Fuel and Light Company, Inc, and Kokomo Gas and Fuel Company, all of which are subsidiaries of NiSource. I am submitting this testimony on behalf of NIPSCO.

Q2. Please summarize your employment and educational background.

A2. I graduated from the College of the Southwest with a bachelor's degree in business, majoring in accounting in 1985. I am a Certified Public Accountant in Indiana. I have held various positions during my career, including Assistant Comptroller for a regional bank and Controller for a regional newspaper. In 1999, I accepted a position with NIPSCO's business planning department. On January 1, 2001, I became an employee of NCS. I was promoted to Segment Controller for the Northern Indiana Energy business unit in August 2002. In February 2008, I became Director of Rates and Regulatory Finance. In June 2008, I was named Executive Director of Rates and Regulatory Finance.

Q3. What are your responsibilities as Executive Director of Rates and Regulatory Finance?

A3. For the Northern Indiana Energy business unit, I have overall responsibility for rate and contract administration, revenue requirements, rate design, electric and gas rates, rules, regulations and contract filings with the Indiana Utility Regulatory Commission ("IURC" or "Commission"), the preparation and filing of all electric and gas cost adjustment filings with the IURC, the preparation and coordination of other regulatory filings, implementation and compliance with state and federal regulatory orders, and all regulatory finance matters.

Q4. Have you previously testified before this Commission?

A4. Yes, on many occasions.

Q5. What is the purpose of your revised direct testimony in this proceeding?

A5. ~~NIPSCO is proposing a two-step rate increase. With regard to Step One, the~~The purpose of my revised direct testimony is to present rate base, capital structure and weighted cost of capital, and results of operations during the test year and on a pro forma basis at both present and proposed rates. I will also describe NIPSCO's proposed tracking mechanisms and changes to existing tracking mechanisms. Other NIPSCO witnesses also address the Company's proposed tracking mechanisms. ~~The purpose of my testimony concerning Step Two is to present the additional revenue requirement, including return, operating costs (including taxes), and depreciation/amortization expense associated with the Sugar Creek generating facility ("Sugar Creek Facility").~~

Q6. Please summarize your testimony for Step One.

A6. As explained by NIPSCO Witness Frank A. Shambo, the Company proposes to remove the cost of fuel and associated taxes from base rates. The Company proposes to recover through base rates the gross margin (total revenues less fuel, purchased power and associated taxes) of \$900,631,816.~~962,393,192.~~ NIPSCO requests a ~~net~~an increase in base rates calculated to produce additional gross margin of \$23,983,452~~85,744,828~~ based on test year pro forma levels.— This amount is calculated to provide the opportunity to earn net operating income of \$195,279,443.~~223,095,808.~~ Support for the ~~Step One~~this request is presented in Petitioner's Exhibits LEM-2 (Revised) through LEM-5-5 (Revised).

Q7. What exhibits are you sponsoring and were the exhibits prepared by you or under your supervision and direction?

A7. I am sponsoring Petitioner's Exhibits LEM-2 (Revised) through LEM-5 (Revised) and LEM-10, all of which were prepared by me or under my supervision and direction.

Q8. Why has your direct testimony been revised from when it was originally prefiled?

A8. The purpose of the revisions to my testimony is to provide the revenue requirements associated with the Sugar Creek generating facility ("Sugar Creek Facility"), which NIPSCO now proposes be included in Petitioner's rate base immediately. My revised testimony also supports an adjustment for a correction made in 2008 which reduces 2007 medical benefits expense due to an error that was discovered after the Case-In-Chief was

filed. This latter adjustment also has a corresponding impact on Petitioner's capital structure.

Q9. Please describe the reason for the change associated with the Sugar Creek Facility.

A9. On May 28, 2008 in Cause No. 43396, the Commission issued an order granting NIPSCO a Certificate of Public Convenience and Necessity ("CPCN") to acquire the Sugar Creek Facility ("CPCN Order"). NIPSCO acquired the equity interests in Sugar Creek Power Company, LLC on May 30, 2008. The prior owners of Sugar Creek had committed the Sugar Creek Facility to the PJM Interconnection, LLC ("PJM") market through May 31, 2010. In the CPCN Order, the Commission found that the Sugar Creek Facility could not be deemed to be "in service" for regulatory purposes while it is committed to the PJM market. Therefore, in its Case-In-Chief as originally filed, NIPSCO requested authorization of a second adjustment (the "Step Two Adjustment") to NIPSCO's basic rates and charges to be implemented when the Sugar Creek Facility would be no longer committed to PJM and instead dispatchable into the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). Subsequent to the filing of its Case-In-Chief, NIPSCO has negotiated an agreement to terminate the commitment of Sugar Creek into PJM and as of December 1, 2008, Sugar Creek is an Internal Designated Network Resource in Midwest ISO. As a result, the originally proposed Step Two Adjustment is now being combined into Step One. In the revised testimony, NIPSCO is presenting a revised revenue requirement, which includes the Sugar Creek Facility in rate base and

operation and maintenance ("O&M") and depreciation/amortization expenses associated with the Sugar Creek Facility in pro forma results of operations.

Q10. Please describe the reason for the change associated with medical benefits expense.

A10. Subsequent to the filing of NIPSCO's Case-In-Chief, the Company discovered that certain medical benefits expenses had been coded incorrectly resulting in an error on the Company's books and records. Certain medical benefits costs that had been incurred for retired workers had actually been recorded as if they had been incurred for the current workforce. The effect of the error was to overstate medical benefits expense and overstate the accrued liability for post-retirement benefits other than pensions pursuant to Statement of Financial Accounting Standard 106 ("SFAS 106"). Making this correction impacts both the pro forma level of medical benefits expense and the component of the capital structure for the amount of SFAS 106 accrual to be recognized at zero cost.

Q11. ~~Q8.~~ Please describe the exhibits relating to Step One.

A11. A8. ~~Petitioner's Exhibit LEM-2,2 (Revised)~~, pages 1 of 4 and 2 of 4, is a statement of NIPSCO's net operating income for the test year ended December 31, 2007 shown on an actual basis, and with pro forma adjustments at current and proposed rates; ~~Petitioner's Exhibit LEM-2,2 (Revised)~~, page 3 of 4, shows the calculation of the proposed revenue increase; and ~~Petitioner's Exhibit LEM-2,2 (Revised)~~, page 4 of 4, is a reconciliation of the requested revenue increase. ~~Petitioner's Exhibit LEM-3 (Revised)~~ consists of a separate page for each income statement adjustment, including those that were reflected in the original case-in-chief filing and the new adjustments for Sugar Creek and the

medical benefits correction, both of which I describe further later in my testimony.
Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2, shows the original cost rate base and
a summary of proposed updates, including Sugar Creek; Petitioner's Exhibit LEM-4,4
(Revised), page 2 of 2, shows the detail of the proposed updates. Petitioner's Exhibit
LEM-5,5 (Revised), page 1 of 3, is the capital structure and overall weighted cost of
capital; Petitioner's Exhibit LEM-5,5 (Revised), page 2 of 3, shows the capital structure
updates; including the change to the capital structure related to the overstatement of
medical benefits expense that I will explain further later in my testimony, and Petitioner's
Exhibit LEM-5,5 (Revised), page 3 of 3, is a schedule of outstanding long-term debt
(unchanged). Petitioner's Exhibit LEM-10 shows the sample schedules proposed to be
utilized with the proposed Reliability Adjustment ("RA") tracking mechanism and is
unchanged from the original filing. Petitioner's Exhibit LEM-6 through LEM-9 in the
original filing have been deleted because they related to NIPSCO's former Step Two
Adjustment proposal.

I. STATEMENT OF OPERATING INCOME

Q12. Q9. Please explain Petitioner's Exhibit LEM-2,2 (Revised).

A12. A9. Petitioner's Exhibit LEM-2,2 (Revised), pages 1 of 4 and 2 of 4, is the Statement of
Operating Income for the twelve months ended December 31, 2007 shown on an actual
basis, and with pro forma adjustments at current and proposed rates. Column B shows
the actual results for the twelve months ended December 31, 2007. Column C shows the
pro forma adjustments made for the fixed, known and measurable changes to reflect

ongoing operations levels at current rates. A detailed listing of the pro forma adjustments is shown on Petitioner's Exhibit LEM-3 (Revised) and ~~are~~each is discussed later in my testimony. Column D shows the reference to each of the detailed adjustments. Column E shows the pro forma levels at current rates. Column F shows the increases necessary to produce the required levels of operating revenue and income. Column G shows the reference to each of the line items in the proposed increase in operating revenue and income. Column H shows the pro forma statement of operating revenue and income at proposed rates. Petitioner's Exhibit LEM-2,2 (Revised), Page 3 of 4, shows the calculation of the proposed base rate change to produce the gross margin revenue increase of ~~\$23,983,452~~\$5,744,828. Petitioner's Exhibit LEM-2,2 (Revised), Page 4 of 4, shows a reconciliation of the requested increase.

II. REVENUE ADJUSTMENTS

Q13. ~~Q10.~~ Please explain Adjustment REV-1 on Petitioner's Exhibit LEM-2,2 (Revised).

A13. ~~A10.~~ Adjustment REV-1 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit) operating revenues in the amount of \$14,604,146 for warmer than normal weather during the 2007 test year. NIPSCO Witness William Gresham discusses the methodology utilized to determine the \$14,604,146 operating revenue adjustment. The dollar amount of the adjustment was calculated by applying Mr. Gresham's MWH adjustments to the applicable rate for each month in the May through October Cooling Degree Days season. This calculation is further detailed in the workpapers to be filed in this proceeding. This adjustment was made to normalize the test year revenues to exclude the variable impact

of weather. If this adjustment is not included, test year operating revenues would be overstated. A corresponding adjustment was made to fuel expense in Adjustment FP-1 on Petitioner's Exhibit LEM-2 (Revised) below.

Q14. **Q11- Please explain Adjustment REV-2 on Petitioner's Exhibit LEM-2.2 (Revised).**

A14. **A11- Adjustment REV-2 on Petitioner's Exhibit LEM-2 (Revised) is to increase (credit)** operating revenues in the amount of \$1,432,424 for the imputation of customer revenue for those customers on Economic Development Rider ("EDR") rates. The customers on these EDR rates receive a discount from the tariff rate level and, since NIPSCO is requesting a rate increase in this proceeding, this discounted amount is required by the tariff to be imputed as an increase (credit) to the test year operating revenues. This adjustment amount was obtained by querying the Customer Information System ("CIS") used to bill customers. The CIS produced a report itemizing the discount given to each customer for each month in the test year, which was used to determine the sum of \$1,432,424. If this adjustment is not included, test year operating revenues would be understated.

Q15. **Q12- Please explain Adjustment REV-3 on Petitioner's Exhibit LEM-2.2 (Revised).**

A15. **A12- Adjustment REV-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (credit)** operating revenues in the amount of \$80,082,674 to account for the expiration of special contract rates applicable to certain large industrial customers. These special contracts provide significant discounts from tariff rates. The adjustment is primarily related to contracts that are set to expire six months following the implementation of the new basic

rates and charges approved in this proceeding in accordance with the terms of the Commission Orders approving the contracts or in accordance with the terms of the contracts themselves. While this adjustment is outside the adjustment period to be used in this Cause, I have calculated the adjustment so as to eliminate the discount. Mr. Shambo further discusses the revenue adjustment for this group of customers. If this adjustment is not included, test year operating revenues would be understated.

Q16. **Q13.-Please explain Adjustment REV-4 on Petitioner's Exhibit LEM-2.2 (Revised).**

A16. **A13.-Adjustment REV-4 on Petitioner's Exhibit LEM-2 (Revised) is to increase (credit)** operating revenues in the amount of \$33,500,000 due to a settlement agreement approved by the Commission's January 30, 2008 Order in Cause No. 38706-FAC71 requiring a refund to customers (the "FAC71 Settlement"). In September 2007, operating revenues were reduced (debited) by \$33,500,000 and a reserve established for return to customers and payment of legal fees of certain parties to the FAC71 Settlement. The \$33,500,000 refund related to certain purchased power costs, in accordance with the FAC71 Settlement. The \$33,500,000 entry was made as a one-time reduction to revenue during the test year. In order to properly reflect the 2007 test year operating revenues at present rates, this nonrecurring entry is required to be adjusted. If this adjustment is not included, test year operating revenues would be understated.

Q17. **Q14.-Please explain Adjustment REV-5 on Petitioner's Exhibit LEM-2.2 (Revised).**

A17. **A14.-Adjustment REV-5 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit)** operating revenues in the amount of \$2,203,737 to eliminate the test year impact of

entries made to reverse a reserve balance previously established related to financial transactions. The reserve had been established in the amount of net "losses" on financial transactions, pending approval of the treatment of these transactions via the fuel adjustment clause ("FAC") mechanism. The FAC71 Settlement (previously discussed in Adjustment REV-4) resolved this issue as well. As a result, this reserve was reversed and a full reserve for the amount of the FAC71 Settlement was established, reducing revenues. If this adjustment is not included, test year operating revenues would be overstated.

Q18. ~~Q15.~~ Please explain Adjustment REV-6 on Petitioner's Exhibit LEM-2.2 (Revised).

A18. ~~A15.~~ Adjustment REV-6 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit) operating revenues in the amount of \$804,136 for a particular group of customers in the metal melting business. For this group of customers, the 2007 test year revenues reflected operating volumes higher than that contractually allowed. This level of volumes above the contract volumes was not anticipated and will not be permitted in the future. Therefore, this adjustment is made in order to reflect test year revenues at a level equivalent to the level of revenues that would have been received had this group of customers not been operating above contract levels. If this adjustment is not included, test year operating revenues would be overstated. Mr. Shambo further discusses the adjustment for this group of customers. A corresponding adjustment was made to fuel expense in Adjustment FP-2 on Petitioners Exhibit LEM-2 (Revised) below.

Q19. ~~Q16.~~ Please explain Adjustment REV-7 on Petitioner's Exhibit LEM-2.2 (Revised).

A19. ~~A16.~~ Adjustment REV-7 on Petitioner's Exhibit LEM-2 (Revised) is to increase (credit) operating revenues in the amount of \$10,955,615 for a one-time unbilled revenue correction recorded in 2007 but related to prior periods. This entry was made as a result of a change in the methodology used to calculate unbilled revenues and receivables. This change resulted in a one-time adjusting entry to the income statement and balance sheet in the test year, reducing revenues. Unbilled revenues and receivables have no impact on customer bills. Unbilled amounts are calculated based on an estimate of the amount of volumes that have not yet been billed at the end of the test year. During the review of the December 2007 closing of the financial books, it was determined that the December 31, 2007 estimate of unbilled volumes was higher than it should be, and that therefore, the unbilled receivable balance would be overstated, if not adjusted. The adjusting entry to correct for this was a credit (reduction) to receivables and a debit (reduction) to revenues, made to the December 2007 books, prior to issuing final financial statements. The analysis of the unbilled volumes revealed a need to revise the methodology being used and also revealed that the method that had been in use affected revenues and receivables for prior years as well as 2007. Therefore, the correcting entry, although made in 2007, affected prior periods as well. Adjustment REV-7 adds back the amount of revenue reduction that relates to periods prior to the test year. The amounts related to prior periods, but recorded in the test year are adjusted out in order to eliminate the impact to the test year operating income statement. If this adjustment is not included, test year

operating revenues would be understated. NIPSCO Witness Mitchell E. Hershberger further discusses the calculation of the unbilled correcting entry.

Q20. Q17. Please explain Adjustment REV-8 on Petitioner's Exhibit LEM-2.2 (Revised).

A20. A17. Adjustment REV-8 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit) operating revenues in the amount of \$50,400,058 for off-system sales revenues. This amount represents the total amount of off-system sales revenues realized in the test year. This adjustment is required because in this proceeding, Petitioner proposes that 100% of future off-system sales margins be passed back to the ratepayers up to \$15 million annually. NIPSCO requests that any off-system sales margins generated beyond the amount of \$15 million annually will be shared, with 80% going to ratepayers. Petitioner is proposing that this be accomplished via the proposed RA tracking mechanism, which is described later in my testimony. Mr. Shambo further discusses this proposal and NIPSCO Witness Curtis Crum describes this mechanism. If this adjustment is not included, operating revenues would be overstated. A corresponding adjustment for the fuel and purchased power costs associated with the 2007 off-system sales revenues is made in Adjustment FP-5 on Petitioner's Exhibit LEM-2 (Revised) below.

Q21. Q18. Please explain Adjustment REV-9 on Petitioner's Exhibit LEM-2.2 (Revised).

A21. A18. Adjustment REV-9 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit) operating revenues in the amount of \$11,790,599 for revenues generated through the sales of emissions allowances. Petitioner proposes that in the future when such sales arise, the net proceeds of such sales will be passed back to the ratepayers via NIPSCO's existing

Environmental Expense Recovery Mechanism ("EERM"). Mr. Shambo further discusses this proposal. If this adjustment is not included, test year operating revenues would be overstated.

Q22. ~~Q19.~~ Please explain Adjustment REV-10 on Petitioner's Exhibit LEM-2.2 (Revised).

A22. ~~A19.~~ Adjustment REV-10 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit) operating revenues in the amount of \$4,726,034 for 2007 transmission revenues from the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO") Schedules 7 and 8 and the revenues from MISO Schedules 1 and 2 associated with Schedules 7 and 8. This adjustment is required due to the fact that, in this proceeding, Petitioner proposes that 100% of future transmission revenues from the aforementioned MISO schedules be passed back to ratepayers via the RA mechanism mentioned previously and described later in my testimony. Mr. Shambo further discusses this proposal. Mr. Crum further describes this mechanism. If this adjustment is not included, test year operating revenues would be overstated.

III. EXPENSE ADJUSTMENTS

A. Fuel and Purchased Power Expense Adjustments

Q23. ~~Q20.~~ Please explain Adjustment FP-1 on Petitioner's Exhibit LEM-2.2 (Revised).

A23. ~~A20.~~ Adjustment FP-1 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (credit) test year operating expenses in the amount of \$3,683,450 to decrease fuel and purchased power costs associated with the operating revenue adjustment for weather normalization as outlined in Adjustment REV-1. The dollar amount of this adjustment was calculated

by applying the base fuel amount of 22.556 mills/kwh to Mr. Gresham's adjustment of 163,303 MWH. If this adjustment is not included, the test year operating expenses would be overstated.

Q24. **Q21. Please explain Adjustment FP-2 on Petitioner's Exhibit LEM-2.2 (Revised).**

A24. ~~A21.~~ Adjustment FP-2 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (credit) test year operating expenses in the amount of \$628,813 to decrease fuel costs related to the group of customers described previously with respect to Adjustment REV-6. If this adjustment is not included, test year operating expenses would be overstated.

Q25. **Q22. Please explain Adjustment FP-3 on Petitioner's Exhibit LEM-2.2 (Revised).**

A25. ~~A22.~~ Adjustment FP-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$100,891 related to fuel handling expenses. It was discovered that mobile fuel handling equipment depreciation had continued to be charged to the D.H. Mitchell Generating Station ("Mitchell"), despite the fact that the coal-fired units at this station ceased generating in 2002. This depreciation was related to coal handling equipment originally utilized at Mitchell. It was determined that the equipment had been physically transferred to the R. M. Schahfer and Michigan City Generating Stations for use but the corresponding transfer on the Company's books and records was not made. Because fuel handling charges are recorded by generating station, the Mitchell fuel handling account (balance sheet account 152) continued to accumulate these charges. Normally, fuel handling charges are accumulated in balance sheet account 152 and cleared to operating expenses in relation to the coal burned during generation.

Because Mitchell was not generating, the amounts were never cleared to expense. In March, 2008 the general accounting department corrected the distribution of fuel handling depreciation that should have been charged to the other generating stations (where the equipment was located and being operated). This correction amounted to \$605,349. These amounts will be cleared to fuel operating expenses on a going forward basis. The correction relates to a six (6) year period, 2002 through 2007. As a result, I have calculated my adjustment to reflect one sixth (1/6) of the adjustment or \$100,891 that would have been included in fuel expense during the 2007 test year. If this adjustment is not included, test year operating expenses would be understated.

Q26. **Q23. Please explain Adjustment FP-4 on Petitioner's Exhibit LEM-2.2 (Revised).**

A26. **A23. Adjustment FP-4 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$840,335 for the increase in the cost of diesel fuel used in the fuel handling equipment in the generating stations. This adjustment is necessary due to the increasing cost of diesel fuel. The amount of the adjustment was calculated by multiplying the quantity of diesel fuel purchased in the test year (479,319 gallons) times a per gallon rate (\$4.032) based on the latest vendor invoice and comparing the result of \$1,932,614 to the total amount spent on diesel fuel in the generating stations during the test year, per the financial books and records, which was \$1,092,279. The difference between the \$1,932,614 and the \$1,092,279 is the adjustment amount of \$840,335. If this adjustment is not included, test year operating expenses would be understated.**

Q27. Q24. Please explain Adjustment FP-5 on Petitioner's Exhibit LEM-2.2 (Revised).

A27. A24. Adjustment FP-5 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$21,285,492 related to Adjustment REV-8. As described previously, this adjustment is due to the fact that, in this proceeding, Petitioner will be proposing that 100% of future off-system sales margins be passed back to the ratepayers up to \$15 million annually. NIPSCO requests that any off-system sales margins generated beyond the amount of \$15 million annually will be shared, with 80% flowed to ratepayers. Petitioner is proposing that this be accomplished via the RA mechanism mentioned previously and described later in my testimony. Mr. Crum also describes this mechanism. If this adjustment is not included, test year operating expenses would be overstated.

B. Operating Expense Adjustments

Q28. Q25. Please explain Adjustment OM-1 on Petitioner's Exhibit LEM-2.2 (Revised).

A28. A25. Adjustment OM-1 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$1,006,664 for an increase in contract labor used by the Generation Department. The Generation Department contracts with outside companies to provide labor for many projects. NIPSCO Witness Phillip W. Pack further discusses this adjustment. If this adjustment is not made, test year operating expenses would be understated.

Q29. Q26. Please explain Adjustment OM-2 on Petitioner's Exhibit LEM-2.2 (Revised).

A29. ~~A26.~~ Adjustment OM-2 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$4,001,238 related to the variable costs required to operate the Company's generating facilities during the test year. This adjustment is based on normalizing test year expenses for unusual periods of generating unit outages. Mr. Sweet discusses how this calculation was made. If this adjustment is not included, test year operating expenses would be understated.

Q30. ~~Q27.~~ Please explain Adjustment OM-3 on Petitioner's Exhibit LEM-2.2 (Revised).

A30. ~~A27.~~ Adjustment OM-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$5,762,558 related to pension expense. Pension calculations are determined by the Company's actuary, Hewitt and Associates, utilizing a number of assumptions including discount rate, life expectancy and return on assets. These factors can and do lead to fluctuations in the level of pension costs from year to year. Pension costs have been highly volatile in recent years, with the range from 2003 to the present varying by nearly \$50 million. To mitigate and normalize this volatility, I calculated a five-year average of pension expense. This calculation leads to a pro forma level of pension cost equaling \$2,139,542 (debit). After allocating to electric using the established common allocation ratios, which are discussed by Mr. Hershberger, the 5-year electric average is \$1,479,493. After deducting the portion capitalized, the 5-year electric average expense is \$1,122,491. The 2007 actual was a credit of \$8,844,269 and the amount allocated to electric was a credit of \$6,115,812. After deducting for the portion capitalized, the 2007 actual electric expense was a credit of \$4,640,067. The 5-

year average electric expense of \$1,122,491 as compared to the 2007 electric credit of \$4,640,067 results in a required increase (debit) adjustment of \$5,762,558. NIPSCO Witness Robert D. Campbell further discusses the company's pension plans. If this adjustment is not included, test year operating expenses would be understated.

Q31. Q28.-Please explain Adjustment OM-4 on Petitioner's Exhibit LEM-2.2 (Revised).

A31. A28.-Adjustment OM-4 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$5,762,460 related to other post retirement employee benefits ("OPEB") expense. OPEB calculations are determined by the Company's actuary, Hewitt and Associates. The 2008 OPEB expense, as calculated by the actuary, was allocated to electric using NIPSCO's common allocation ratios, and was then compared to the actual 2007 electric portion of OPEB expense in the test year to determine the amount of this pro forma adjustment. Unlike the pension expense described above, OPEB is not subject to market fluctuations, and therefore the 2008 estimate calculated by Hewitt and Associates is believed to be a representative level of OPEB expense. If this adjustment is not included, test year operating expenses would be understated.

Q32. Q29.-Please explain Adjustment OM-5 on Petitioner's Exhibit LEM-2.2 (Revised).

A32. A29.-Adjustment OM-5 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$5,083,259 related to employee wage increases. The Company currently has in effect for its physical and clerical bargaining unit employees, contracts effective June 1, 2004 and extending through May 31, 2009. In

accordance with those contracts, wage rates increase at the end of each calendar year from 2004 through 2008. The 2007 year end wage rate increase was 3%; wages will increase again by 3% at the end of 2008. I have adjusted for the effect of the employee wage increase that took effect upon the conclusion of the test year and then also adjusted for the increase that will take effect 12 months thereafter at the end of 2008. The 2007 adjustments for the physical and clerical employees are \$3,311,418 and \$562,924, respectively. The 2008 adjustments are \$3,410,760 and \$579,812, respectively. The non-bargaining unit employees of NIPSCO receive wage increases on March 1 of each year. In order to annualize the 2007 test year expense, the wages for the January and February, 2007 period were increased by approximately 3% resulting in \$239,364. In addition, the non-bargaining unit employees of NIPSCO received a 3.25% increase effective March 1, 2008. In order to adjust for the 2008 wage increase, the normalized wages for 2007 were increased by 3.25% resulting in an increase of \$1,584,744. The total increase for the non-bargaining unit and bargaining unit wage increase adjustments resulted in an increase of \$9,689,022, which was then allocated to electric, using the established common allocation ratios, net of amounts capitalized, resulting in an electric operating expense increase of \$5,083,259. If this adjustment is not included, test year operating expenses would be understated.

Q33. Q30.

Please explain Adjustment OM-6 on Petitioner's Exhibit LEM-2.2 (Revised).

A33. ~~A30.~~ Adjustment OM-6 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount \$916,264 related to incentive compensation in excess of the "trigger" level. During the 2007 test year, incentive amounts were expensed equal to 125% of the "trigger." This adjustment reduces expense to the "trigger" level amount, which is historically the "normal" level for NIPSCO expenses, and adjusts for true-ups recorded to expense during the test year that were related to the prior year. True-ups occur due to the method by which incentive plan expense is accrued. Incentive plan expense is accrued in the current year based on an estimate of what is expected to be paid out in the following year. Any difference between the amount paid out and the amount accrued is "trued-up" in the payout year, resulting in debits or credits to expense related to the prior year. These adjustments have been offset by the additional incentive compensation for the wage increases outlined in Adjustment OM-5. The adjustment was calculated by comparing the amount currently being accrued for 2008, which anticipates a "trigger" level payout with the amount recorded in 2007. The amount being accrued for 2008, after deducting for the portion capitalized is \$4,957,350. The net amount, after true-ups, and after deducting for the portion capitalized recorded in the 2007 test year was \$6,244,139. The difference between these two amounts is \$1,286,789. A downward adjustment for profit sharing expense of \$38,249 was also computed in the same manner and for the same reasons. The combined total of the two adjustments above was \$1,325,038. After allocating to electric, the net adjustment to electric operating expenses is a reduction (credit) to operating expenses of \$916,264. Mr. Campbell further discusses

the Incentive Plan. If this adjustment is not included, test year operating expenses would be overstated.

Q34. **Q31. Please explain Adjustment OM-7 on Petitioner's Exhibit LEM-2.2 (Revised).**

A34. **A31.** Adjustment OM-7 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$3,925,207 to reflect additional staffing required as a result of workforce aging and retirements. This required additional staffing was not reflected in the test year, and therefore an adjustment is required in order to reflect ongoing levels. This adjustment was calculated by determining the number of replacements that will be needed in each functional area over the next five years, applying the appropriate hourly wage for bargaining unit positions and the appropriate salary for supervisory positions, then applying the cost of benefits. The total of these amounts for the five-year period was averaged, resulting in an annual amount of \$3,925,207. Mr. Campbell discusses the workforce aging program and the number of employees required to provide the necessary services to our customers. If this adjustment is not included, test year operating expenses would be understated.

Q35. **Q32. Please explain Adjustment OM-8 on Petitioner's Exhibit LEM-2.2 (Revised).**

A35. **A32.** Adjustment OM-8 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$5,016,101 to reflect additional staffing required to fill current vacancies in positions that NIPSCO is actively in the process of securing candidates. This adjustment is being made in order to reflect the proper level of salary expense, since the 2007 test year did not reflect salary expense for these positions

that had not yet been filled. This amount was calculated by obtaining a list of 104 vacancies from the Human Resources department and applying the appropriate hourly wage for each bargaining unit position and the appropriate salary amount for each supervisory position. Benefits were then added, as well as incentive compensation based on the incentive range for the position level. The resulting amount was \$9,561,015. Vacancies for electric-specific positions were identified as such and common positions were allocated to electric based on the established common allocation ratios. After determining the electric amount and deducting for the portion capitalized, the net adjustment was an increase (debit) to electric operating expenses of \$5,016,101. Mr. Campbell discusses the number of vacancies and the process NIPSCO utilizes to fill vacant positions. If this adjustment is not included, test year operating expenses would be understated.

Q36. **Q33. Please explain Adjustment OM-9 on Petitioner's Exhibit LEM-2-2 (Revised).**

A36. **A33. Adjustment OM-9 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit)** test year operating expenses in the amount of \$6,413,789 to reflect additional staffing required to fill 83 new positions necessitated by the organizational structure changes occurring for the Indiana business unit. This adjustment is being made in order to reflect the proper level of salary expense, since the 2007 test year did not reflect salary expense for these positions. NIPSCO currently is in the process of filling these positions. These staffing changes include: senior level positions in Customer Engagement and Communications intended to increase the Indiana focus; additional management positions

in Service Delivery; additional positions needed for new FERC and NERC compliance requirements; a new Resource Planning department; and several additional positions in Generation. The Company also is increasing staffing levels of the Rates department, including positions with responsibility for the DSM programs being developed by the Company to be proposed in a separate filing, and new Regulatory and Legislative Affairs policy management positions, to be located in the Company's Indianapolis office. Estimated salary amounts were applied according to the position level, and benefits and incentive amounts were added in a manner similar to that described in Adjustment OM-8 for staffing vacancies. Positions specific to electric were designated as such, and common positions were allocated to electric using the established common allocation ratios. After determining the electric amount and deducting for the portion capitalized, the net adjustment was an increase (debit) to electric operating expenses of \$6,413,789. NIPSCO Witness Eileen O'Neill Odum describes the Indiana business unit organizational structure and the need for these additional positions. If this adjustment is not included, test year operating expenses would be understated.

Q37. **Q34. Please explain Adjustment OM-10 on Petitioner's Exhibit LEM-2-2 (Revised).**

A37. **A34. Adjustment OM-10 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit)**
test year operating expenses in the amount of \$448,589 to reflect additional staffing and protective safety equipment required to comply with new regulations and safety initiatives, as these costs were not reflected in 2007 test year expense. The safety program and initiatives and the calculation of this adjustment are discussed by NIPSCO

Witness Timothy A. Dehring. If this adjustment is not included, test year operating expenses would be understated.

Q38. Q35- Please explain Adjustment OM-11 on Petitioner's Exhibit LEM-2.2 (Revised).

A38. A35- Adjustment OM-11 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$55,425 to reflect lobbying costs and payment adjustments included in the Edison Electric Institute ("EEI") dues expense during the test year. The Company rejoined the EEI effective the 4th quarter of 2006. In December 2006, the Company accrued an estimated amount for 2006 EEI dues because the bill had not yet been received. In January 2007, when the bill was received and paid, the amount due was less than estimated. As a result, a credit to expense of \$72,588 was recorded in 2007, which related to the 2006 period. To normalize the test year for EEI dues, an adjustment of \$72,588 was added (debit) to increase operating expenses. A full year of EEI dues was reflected in 2007 expenses, but since the EEI membership dues invoice includes an amount related to lobbying costs, an adjustment has been made to reduce (credit) expenses by \$128,013. The net result of these adjustments related to EEI dues is a decrease (credit) to test year operating expenses of \$55,425. If this adjustment is not included, test year operating expenses would be overstated.

Q39. Q36- Please explain Adjustment OM-12 on Petitioner's Exhibit LEM-2.2 (Revised).

A39. A36- Adjustment OM-12 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$60,063 to remove all institutional and

goodwill advertising costs included in account E930.1. If this adjustment is not made, test year operating expenses would be overstated.

Q40. Q37.

Please explain Adjustment OM-13 on Petitioner's Exhibit LEM-2-2 (Revised).

A40. ~~A37.~~ Adjustment OM-13 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$200,000 to reflect uncollectible accounts expense. As a result of the Bailly Generating Station N1 refund ordered in this Commission's February 21, 1990 Order in Cause No. 37972, the Company was required to offset this amount against uncollectible accounts expense in the Company's next electric base rate case. If this adjustment is not made, test year operating expenses would be overstated.

Q41. ~~Q38.~~ Please explain Adjustment OM-14 on Petitioner's Exhibit LEM-2-2 (Revised).

A41. ~~A38.~~ Adjustment OM-14 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$71,796 to reflect increased postal rates effective in May 2007 and May 2008. This adjustment reflects the electric portion of increased postage costs for customer billing. The adjustment was calculated by increasing 2007 test year postage expense in accordance with increased postal rates and then annualizing the increases to reflect ongoing annual amounts. The computation began with 2007 test year actual postage expense of \$3,248,277. I then annualized the postal increase that took effect May 14, 2007. This resulted in a 2007 adjusted amount of \$3,312,597. This amount was then adjusted for the postal increase that took effect May 14, 2008, totaling \$3,432,417. The difference between the \$3,432,417 and the 2007 actual amount of \$3,248,277 is \$184,140. This amount was then allocated between electric and gas based upon the number of customers, resulting in a net increase (debit) in

electric operating expenses of \$71,796. If this adjustment is not included, test year operating expenses would be understated.

Q42. Q39. Please explain Adjustment OM-15 on Petitioner's Exhibit LEM-2.2 (Revised).

A42. A39. Adjustment OM-15 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$799,403 to reflect increased gasoline and diesel fuel costs. The average cost of bulk gasoline and diesel fuel during the 2007 test year was recalculated utilizing a more current cost (March 2008). The amount of the adjustment was calculated by multiplying the quantity of gasoline and diesel fuel used in the test year times the per gallon rates based on the latest vendor invoices, allocating to electric, and comparing the resulting amount to the total amount spent on gasoline and diesel fuel during the test year. If this adjustment is not included, test year operating expenses would be understated.

Q43. Q40. Please explain Adjustment OM-16 on Petitioner's Exhibit LEM-2.2 (Revised).

A43. A40. Adjustment OM-16 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$2,078,499 to reflect additional costs for vegetation management. Mr. Dehring discusses this adjustment. If this adjustment is not included, test year operating expenses would be understated.

Q44. Q41. Please explain Adjustment OM-17 on Petitioner's Exhibit LEM-2.2 (Revised).

A44. A41. Adjustment OM-17 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$2,318,771 to reflect items related to

services provided by NCS. NIPSCO Witness Susanne M. Taylor discusses the allocation processes and the pro forma adjustment to the 2007 test year. Mr. Hershberger discusses the processes used by NIPSCO accounting to review charges received from NCS and the processes used to identify the adjustment noted above. The \$2,318,771 adjustment is the sum of the adjustments proposed by these two witnesses. If this adjustment is not included, test year operating expenses would be overstated.

Q45. ~~Q42.~~ Please explain Adjustment OM-18 on Petitioner's Exhibit LEM-2-2 (Revised).

A45. ~~A42.~~ Adjustment OM-18 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$3,187,121 to annualize a change resulting from an improvement in methodology used to allocate common costs between the gas and electric business for NIPSCO. The methodology change took place in the second quarter of the test year. The common allocation methodology and practice historically used was based on a 1968 study. During 2006, a comprehensive review of the methodology was undertaken and changes were made to more accurately reflect the current operations of the Company. In addition, the study was developed to align the cost allocations with the corporate services allocation methodology to provide consistency of allocation methods within NiSource. A complete description of the common allocation study and the methodology is discussed by Mr. Hershberger. The adjustment is made in order to properly reflect a full year of allocated electric costs. The adjustment is computed by applying to the first quarter of the test year the allocation percentages (similar to those in Mr. Hershberger's Petitioner's Exhibit MEH-4) that would have applied at the time using

the new methodology. If this adjustment is not included, test year operating expenses would be understated.

Q46. Q43.

Please explain Adjustment OM-19 on Petitioner's Exhibit LEM-2.2 (Revised).

A46. A43- Adjustment OM-19 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$366,293 for non-recoverable advertising costs. To ensure that non-recoverable advertising costs were appropriately excluded, this adjustment was calculated by removing all general advertising costs, per the financial books and records. A review of advertising costs was then undertaken, and those costs related to appropriately recoverable advertising, such as recruitment and safety, were added back in. These types of costs produce a material benefit to the ratepayers. Copies of such advertising are included in the workpapers to be filed in this proceeding. The result was a net reduction (credit) to electric operating expenses of the \$366,293 noted above. If this adjustment is not made, test year operating expenses would be overstated.

Q47. Q44- Please explain Adjustment OM-20 on Petitioner's Exhibit LEM-2.2 (Revised).

A47. A44- Adjustment OM-20 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$84,528 to remove certain non-recoverable charges, such as lobbying, community sponsorships, and customer and employee relations expenses. The details of this adjustment can be found in the workpapers to be filed in this proceeding. If this adjustment is not included, test year operating expenses would be overstated.

Q48. Q45- Please explain Adjustment OM-21 on Petitioner's Exhibit LEM-2.2 (Revised).

A48. A45- Adjustment OM-21 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$28,785 to reflect the increased lease costs

in NIPSCO's Indianapolis office, as a result of additional new employees and the relocation of an employee from Merrillville. This adjustment was calculated by obtaining the new annual lease amount, deducting for space occupied by the NIPSCO lobbyist because those charges are non-recoverable, and allocating to electric. If this adjustment is not included, test year operating expenses would be understated.

Q49. **Q46- Please explain Adjustment OM-22 on Petitioner's Exhibit LEM-2.2 (Revised).**

A49. **A46- Adjustment OM-22 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$2,067,189 to reflect increased electric property insurance costs. This adjustment is based on new insurance premiums effective July, 2008. The premium increases are a result of increased electric generation property values as used by insurance underwriters for premium determinations. If this adjustment is not included, test year operating expenses would be understated.**

Q50. **Please explain Adjustments SCOM-23 on Petitioner's Exhibit LEM-2 (Revised).**

A50. **Adjustment SCOM-23 increases (debits) operating expenses in the amount of \$1,870,352 to reflect variable O&M expense required to operate the Sugar Creek Facility. Mr. Pack further describes the calculation of this adjustment.**

Q51. **Please explain Adjustment SCOM-24 on Petitioner's Exhibit LEM-2 (Revised).**

A51. **Adjustment SCOM-24 increases (debits) operating expenses in the amount of \$4,048,947 for other O&M expenses, which consists of fixed O&M expense for the plant as well as**

property insurance related to the Sugar Creek Facility. Mr. Pack further describes the calculation of this adjustment.

Q52. Please explain Adjustment OM-25 on Petitioner's Exhibit LEM-2 (Revised).

A52. Adjustment OM-25 decreases (credits) test year operating expenses in the amount of \$5,276,650 to reflect a correction to the 2007 test year medical benefits expense. This correction was made in 2008 subsequent to the filing of the Case-In-Chief. As I indicated previously, during the test year, certain medical benefits costs that the Company paid were coded incorrectly. The result was that they were recorded incorrectly as medical benefits for current employees when in fact they were medical benefits incurred and paid for retired employees. The total amount of the error was \$10,040,730. Of that amount, \$7,630,730 was recorded as expense (i.e., the portion of labor that was expensed). The portion of the reduction in medical benefits expense allocable to electric is \$5,276,650. Mr. Campbell further describes the circumstances of the error.

C. Depreciation and Amortization Adjustments

Q53. Q47. Please explain Adjustment DA-1 on Petitioner's Exhibit LEM-2.2 (Revised).

A53. A47. Adjustment DA-1 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$227,322 to reflect the change in common allocation methodology implemented in the second quarter of the test year. As mentioned above, Mr. Hershberger discusses this change in methodology. If this adjustment is not included, test year operating expenses would be understated.

| Q54. Q48. _____

Please explain Adjustment DA-2 on Petitioner's Exhibit LEM-2.2 (Revised).

A54. ~~A48.~~ Adjustment DA-2 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of ~~\$9,583,660~~20,820,517 to reflect implementation of new depreciation rates on electric and common property, and depreciation/amortization expense associated with Sugar Creek. The annual depreciation/amortization expense for Sugar Creek, included in this adjustment, is \$11,236,857. NIPSCO Witness John J. Spanos has performed a comprehensive depreciation study for electric plant and common plant. The adjustment is based upon his proposed depreciation rates. If this adjustment is not included, test year operating expenses would be understated.

Q55. **Q49. Please explain Adjustment DA-3 on Petitioner's Exhibit LEM-2.2 (Revised).**

A55. ~~A49.~~ Adjustment DA-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$8,256,052 to reflect amortization of the deferral of non-fuel Midwest ISO costs to a regulatory asset beginning August 1, 2006, as approved by this Commission in its June 1, 2005 Order in Cause No. 42685. The amount of total MISO costs deferred to a regulatory asset at December 31, 2007 amounted to \$13,990,057. In addition, MISO non-fuel costs to be deferred through the end of the adjustment period are estimated to be \$10,778,099. The total amount of the deferral is estimated to be \$24,768,156 by year-end 2008. The Company proposes a three-year amortization period. The estimated total of \$24,768,156 amortized over a three-year period is \$8,256,052 annually and therefore requires an increase in electric amortization

expense. Because MISO non-fuel costs will continue to be incurred and deferred as described above beyond the end of 2008, and to ensure recovery of all MISO non-fuel costs, the Company proposes that any difference between the estimated and actual amount of the deferral be included as an adjustment via the RA mechanism mentioned previously and described later in my testimony. Mr. Crum provides a detailed discussion of the RA mechanism. If this adjustment is not included, test year operating expenses would be understated.

Q56. ~~Q50.~~ Please explain Adjustment DA-4 on Petitioner's Exhibit LEM-2.2 (Revised).

A56. ~~A50.~~ Adjustment DA-4 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$1,979,286 to reflect rate case costs. The Company has estimated a total cost of \$5,937,859 for legal, consulting and expert witness testimony and proposes a three-year amortization period. The total estimated cost over a proposed three-year amortization period is \$1,979,286, and, therefore, requires an increase in electric amortization expense. This estimate will be updated at the time rebuttal testimony is filed to reflect a more accurate amount and the pro forma adjustment will be adjusted at that time. If this adjustment is not included, test year operating expenses would be understated.

Q57. ~~Q51.~~ Please explain Adjustment DA-5 on Petitioner's Exhibit LEM-2.2 (Revised).

A57. ~~A51.~~ Adjustment DA-5 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$935,424 to reflect the completion of the amortization of the Pure Air regulatory asset created as a result of the Commission's

October 16, 1991 Order in Cause No. 38849-S1. This asset will be fully amortized by the end of the adjustment period and I have therefore eliminated this expense. If this adjustment is not included, test year operating expenses would be overstated.

Q58. Q52.

Please explain Adjustment DA-6 on Petitioner's Exhibit LEM-2.2 (Revised).

A58. A52. Adjustment DA-6 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$40,657 to reflect the change in common allocation methodology in the second quarter of the test year. Mr. Hershberger further discusses this change and the resulting adjustment. If this adjustment is not included, test year operating expenses would be understated.

Q59. Please explain Adjustment SCDA-7 in Petitioner's Exhibit LEM-2 (Revised).

A59. Adjustment SCDA-7 is the increase (debit) to electric amortization expenses for \$1,459,652 for the amortization of the depreciation/amortization expense of the Sugar Creek Facility proposed to be deferred beginning December 1, 2008 through December 31, 2009. The amortization amount is equal to the amount of annual Sugar Creek depreciation/amortization, which is \$11,236,857, reduced by \$4,500,000 (the annual depreciation on the Mitchell plant pursuant to the FAC71 Settlement), divided by twelve to derive a monthly amount of \$561,405 and multiplied by thirteen months to total a deferred amount of \$7,298,262. I have projected the total deferred amount to the anticipated date of an Order in this proceeding. Pursuant to the FAC-71 Settlement, this amount is amortized over a five-year period, resulting in an annual amount of \$1,459,652..

Q60. Please explain Adjustment SCDA-8 in Petitioner's Exhibit LEM-2 (Revised).

A60. Adjustment SCDA-8 is the increase (debit) to electric amortization expenses for \$4,541,120 for the amortization of the deferred carrying charges on the Sugar Creek

Facility. This amount represents the amount of carrying charges proposed to be deferred from December 1, 2008 through December 31, 2009, the anticipated date when rates will become effective. This amount was calculated by multiplying the Sugar Creek rate base gross plant amount of \$322,446,401 (net book value at December 1, 2008) by a rate of 6.5% to derive an annual carrying cost of \$20,959,016, divided by twelve for a monthly amount of \$1,746,585 and multiplied by thirteen months to total a deferred amount of \$22,705,601. This amount is amortized over a five-year period, resulting in an annual amount of \$4,541,120.

Q61. Why are you using a 6.5% rate to calculate carrying charges and using a five year amortization period?

A61. That rate is consistent with the terms of the FAC71 Settlement as is the five year amortization period.

D. Tax Adjustments

Q62. Q53. Please explain Adjustment OTX-1 on Petitioner's Exhibit LEM-2.2 (Revised).

A62. A53. Adjustment OTX-1 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$1,045,127 to reflect decreased real estate property taxes as a result of the change in common allocation methodology in the second quarter of the test year. Mr. Hershberger also discusses this change. If this adjustment is not included, test year operating expenses would be overstated.

Q63. Q54. Please explain Adjustment OTX-2 on Petitioner's Exhibit LEM-2.2 (Revised).

A63. A54. Adjustment OTX-2 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$12,431 to reflect decreased federal excise tax as a result of the change in common allocation methodology in the second quarter of the test year. Mr. Hershberger further discusses this change. If this adjustment is not included, test year operating expenses would be overstated.

Q64. Q55. _____

Please explain Adjustment OTX-3 on Petitioner's Exhibit LEM-2.2 (Revised).

A64. ~~A55.~~ Adjustment OTX-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$98,809 to reflect an increase in the Indiana state sales tax percentage from 6% to 7%. This adjustment was calculated by determining the electric Indiana sales tax expense for 2007 and adjusting it for the increase in the state sales tax rate. If this adjustment is not included, test year operating expenses would be understated.

Q65. ~~Q56.~~ Please explain Adjustment OTX-4 on Petitioner's Exhibit LEM-2.2 (Revised).

A65. ~~A56.~~ Adjustment OTX-4 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$18,672 to remove property tax expense for non-utility property. If this adjustment is not included, test year operating expenses would be overstated.

Q66. ~~Q57.~~ Please explain Adjustment OTX-5 on Petitioner's Exhibit LEM-2.2 (Revised).

A66. ~~A57.~~ Adjustment OTX-5 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$1,257,455 to reflect increased payroll taxes. This adjustment increases payroll taxes for the wage and incentive plan changes discussed in Adjustments OM-5, OM-6, OM-7, OM-8, OM-9, and OM-10. In addition, the adjustment includes an adjustment for payroll taxes related to the increase in taxable base wages for social security tax from \$95,200 to \$102,000. If this adjustment is not included, test year operating expenses would be understated.

Q67. Q58.

Please explain Adjustment OTX-6 on Petitioner's Exhibit LEM-2.2 (Revised).

A67. ~~A58.~~ Adjustment OTX-6 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$6,467,208 to reflect Utility Receipts Tax ("URT") as calculated by NIPSCO Witness John M. O'Brien. As I previously discussed, URT associated with fuel and purchased power should not be recovered through base rates in order to be consistent with the Company's request to remove the cost of fuel and purchased power from base rates. In Column F of this same schedule, you will see that I have reclassified URT on fuel and purchased power as an increase (credit) to operating revenue of \$7,177,052 on line 14. In addition, I have reflected an increase (debit) to fuel and purchased power expenses on line 23 as an adjustment of \$7,177,052. These adjustments are made so that the URT on fuel and purchased power will not be recovered through base rates. The adjustments on lines 14 and 23 were calculated by applying the URT rate of 1.40% to the total cost of fuel and purchased power. They are identified as Adjustment OTX-6A in order to differentiate them from Adjustment OTX-6, which is the net effect of an increase (debit) to other tax expense of \$709,844 to reflect the URT on the proposed change in revenue requirement and the decrease (credit) of \$7,177,052 to other tax expense related to fuel and purchased power described above. The detailed calculation can be seen in Petitioner's Exhibit LEM-3.

Q68. ~~Q59.~~ **Please explain Adjustment OTX-7 on Petitioner's Exhibit LEM-2.2 (Revised).**

A68. ~~A59.~~ Adjustment OTX-7 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$211,218 to reflect Public Utility Fees

related to the increased pro forma revenues at present rates. This amount was calculated by applying the current Public Utility Fees rate to the pro forma revenue adjustments. If this adjustment is not included, test year operating expenses would be understated.

Q69. Please explain Adjustment SCOTX-8 in Petitioner's Exhibit LEM-2 (Revised).

A69. Adjustment SCOTX-8 increases (debits) operating expenses in the amount of \$697,593 and is associated with property tax expense on the Sugar Creek Facility. The calculation of this adjustment is described by Mr. O'Brien.

Q70. Q60. Please explain Adjustment ITX-1 on Petitioner's Exhibit LEM-2.2 (Revised).

A70. A60. Adjustment ITX-1 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$1,517,68311,868,829 to reflect lower income taxes. This adjustment is the difference between the test year federal and state income taxes and the Income Taxes Included in Net Operating Income in Petitioner's Exhibit JMO-2 sponsored by Mr. O'Brien. This amount includes the interest synchronization calculation Mr. O'Brien performs, plus the other adjustments he describes. If this adjustment is not included, test year operating expenses would be overstated.

IV. PROPOSED REVENUE INCREASE

Q71. Q61. Please explain Adjustment PF-1 on Petitioner's Exhibit LEM-2.2 (Revised).

A71. A61. Adjustment PF-1 on Petitioner's Exhibit LEM-2 (Revised) shows the calculation of the increased gross margin from base rates in the amount of \$23,983,452,85,744,828.

which is calculated to provide the opportunity to earn an ~~8.34%~~ return of 8.37% on net original cost rate base of ~~\$2,341,480,136~~ 2,665,421,829. The increased revenue requirement is calculated by determining the requested increase in operating income. The requested level of operating income is determined by applying the proposed rate of return of ~~8.34~~ 8.37% to the net original cost rate base for NIPSCO (shown on page 3 of Petitioner's Exhibit LEM-2 (Revised)). The requested increase in net operating income is ~~\$13,996,413~~ 50,039,503. The increase in operating income is then grossed up for: (a) Federal income taxes, (b) State income taxes, (c) URT, (d) Public Utility Fees, and (e) uncollectible accounts. The resulting proposed increase in revenue requirement is \$85,744,828.

Public Utility Fees, and (e) uncollectible accounts. The resulting proposed increase in revenue requirement is \$23,983,452.

Q72. Q62. Please explain Adjustment PF-2 on Petitioner's Exhibit LEM-2.2 (Revised).

A72. A62. Adjustment PF-2 on Petitioner's Exhibit LEM-2 (Revised) reflects the additional uncollectible accounts expense on the revenue increase by multiplying the proposed increase in revenue requirement by the multiplier of 0.226593%, for an increase in expense of \$54,345194,292 at the proposed rates level.

Q73. Q63. Please explain Adjustment PF-3 on Petitioner's Exhibit LEM-2.2 (Revised).

A73. A63. Adjustment PF-3 on Petitioner's Exhibit LEM-2 (Revised) is a calculation of the URT applicable to the proposed increase in revenue requirement and is calculated by applying the 1.4% rate to the proposed increase of \$23,983,452,85,744,828, resulting in an increase of \$335,768,1,200,428.

Q74. Q64. Please explain Adjustment PF-4 on Petitioner's Exhibit LEM-2.2 (Revised).

A74. A64. Adjustment PF-4 on Petitioner's Exhibit LEM-2 (Revised) is a calculation of the Public Utility Fees applicable to the proposed increase in revenue requirement and is calculated by applying the 0.1204% rate to the proposed increase of \$23,983,452,85,744,828, resulting in an increase of \$28,876,103,237.

Q75. Q65. Please explain Adjustment PF-5 on Petitioner's Exhibit LEM-2.2 (Revised).

A75. A65. Adjustment PF-5 on Petitioner's Exhibit LEM-2 (Revised) is to account for income taxes applicable to the proposed increase in net operating income. It is calculated by

applying the Federal income tax rate to the pro forma federal taxable income and the
Indiana state income tax rate to the pro forma state taxable income, resulting in an
increase of \$9,568,050.34,207,368. As Mr. _____

O'Brien explains, federal and state taxable incomes are not the same due to different deductions.

Q76. Q66. Please explain Petitioner's Exhibit LEM-3.3 (Revised).

A76. A66. Petitioner's Exhibit LEM-3 (Revised) consists of a separate page for each income statement adjustment, including those filed in the original Case-In-Chief that are unchanged and the adjustments related to Sugar Creek and the medical benefits correction described earlier in this testimony. The individual pages present additional detail where needed to further explain the amounts included in Petitioner's Exhibit LEM-2 (Revised) and discussed individually in my testimony. Where appropriate, the workpapers to be filed in this proceeding provide further detail.

V. NET ORIGINAL COST RATE BASE

Q77. Q67. Please explain Petitioner's Exhibit LEM-4.4 (Revised).

A77. A67. Petitioner's Exhibit LEM-4.4 (Revised), page 1 of 2, quantifies NIPSCO's net original cost rate base as of December 31, 2007, including updates, which I describe later in my testimony. Column B shows the actual rate base as of December 31, 2007, per NIPSCO's books. Column C shows the debit and credit updates to rate base by line item. Column D shows the total net original cost rate base with the rate base updates reflected. Petitioner's Exhibit LEM-4.4 (Revised), page 2 of 2, shows the detail of the rate base updates, which is further discussed below.

Q78. ~~Q68.~~ Please explain Update RB-1 on Petitioner's Exhibit LEM-4,4 (Revised), page 2 of 2.

A78. ~~A68.~~ Update RB-1 on Petitioner's Exhibit LEM-4,4 (Revised), page 2 of 2, decreases (credits) utility plant in service in the amount of \$175,909,015 to reflect the removal of units at Mitchell, which are being retired. Ms. Odum and Mr. Sweet further discuss the Company's plans regarding Mitchell.

Q79. ~~Q69.~~ Please explain Update RB-2 on Petitioner's Exhibit LEM-4,4 (Revised), page 2 of 2.

A79. ~~A69.~~ Update RB-2 on Petitioner's Exhibit LEM-4,4 (Revised), page 2 of 2, decreases (debits) accumulated depreciation reserve in the amount of \$178,072,088 to reflect the retirement of Mitchell.

Q80. ~~Q70.~~ Please explain Update RB-3 on Petitioner's Exhibit LEM-4,4 (Revised), page 2 of 2.

A80. ~~A70.~~ Update RB-3 on Petitioner's Exhibit LEM-4,4 (Revised), page 2 of 2, decreases (credits) utility plant in service in the amount of \$19,395,755 to reflect removal of the Michigan City Generating Station Units 2 and 3, which are being retired. Ms. Odum and Mr. Sweet further discuss the Company's plans regarding Units 2 and 3 at the Michigan City Generating Station.

Q81. ~~Q71.~~ Please explain Update RB-4 on Petitioner's Exhibit LEM-4,4 (Revised), page 2 of 2.

A81. ~~A71.~~ Update RB-4 on Petitioner's Exhibit LEM-4,4 (Revised), page 2 of 2, decreases (debits) accumulated depreciation reserve in the amount of \$18,096,416 to reflect the retirement of the Michigan City Generating Station Units 2 and 3.

Q82. ~~Q72.~~ Please explain Updates RB-5 through RB-10 on Petitioner's Exhibit LEM-4,4 (Revised), page 2 of 2.

A82. ~~A72.~~ As discussed in greater detail by Mr. Dehring and NIPSCO Witness Robert Greneman, the Company implemented the FERC Seven Factor Test relating to the electric transmission and distribution facilities as set forth in FERC Order No. 888. This resulted in \$108,644,289 of transmission assets being re-classified as distribution assets and

\$14,599,077 of distribution assets being re-classified as transmission assets. This update has no impact on total plant in service values. In addition, the accumulated depreciation and amortization reserves were adjusted. These updates are identified as RB-5 and RB-6. In addition, the Company made updates to rate base to reflect the impact of an error made in performing certain plant retirements and made other adjusting entries to correct assets that had been misclassified as to specific plant account. These updates are identified as RB-7 through RB-10. Mr. Hershberger further discusses these adjustments.

Q83. Please explain Update RB-11 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2.

A83. Update RB-11 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2, increases (debits) rate base in the amount of \$1,495,291 to reflect Materials and Supplies for the Sugar Creek Facility.

Q84. Please explain Updates RB-12 and RB-13 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2.

A84. Updates RB-12 and RB-13 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2, reflect, respectively, the increase (debit) to rate base in the amount of \$328,064,833 to reflect gross utility plant for the Sugar Creek Facility and the increase (credit) to accumulated depreciation for the Sugar Creek Facility for the period June 1, 2008 through November 30, 2008.

Q85. Q73. Please discuss the Deferred Charges shown on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2.

A85. A73.-The deferred charges shown on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2, relate to the unamortized balance at December 31, 2007 of deferred charges in connection with the (1) Pure Air flue gas desulfurization ("FGD") at the Bailly Generating Station, (2) R. M. Schahfer Generating Station Units 17 and 18, and (3) prepaid pension asset.

Q86. Q74.-Please explain the Pure Air Deferred Charges on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2.

A86. A74.-The Pure Air Deferred Charges on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2, in the amount of \$526,218 represent the remaining unamortized balance of the regulatory asset established in Cause No. 43188. This asset will be fully amortized by year-end 2008.

Q87. Q75.-Please explain the Unit 17 Depreciation on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2.

A87. A75.-The Unit 17 Depreciation on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2, in the amount of \$542,928 relates to the deferral of depreciation on Schahfer Unit 17 after it went into service and before entry of the Commission's August 3, 1983 Order in Cause No. 37023 (including Unit 17 in NIPSCO's rate base). Pursuant to the Commission's April 20, 1983 Order in Cause No 37129, the Company was authorized to defer and amortize the deferred depreciation over the remaining life of Schahfer Unit 17. The

amount of \$542,928 is the unamortized amount of deferred charges at December 31, 2007.

Q88. Q76. Have you removed from rate base the unamortized amount of the Schahfer Unit 17 disallowance ordered by the Commission?

A88. A76. Yes, I removed the unamortized amount of the disallowance of \$4,334,003, which consists of gross plant of \$31,733,655 and accumulated amortization of \$27,399,652 as shown on Petitioner's Exhibit LEM-4.4 (Revised).

Q89. Q77. Please explain the Unit 18 Depreciation and Carrying Charges on Petitioner's Exhibit LEM-4.4 (Revised), page 1 of 2.

A89. A77. The Unit 18 Depreciation and Carrying Charges on Petitioner's Exhibit LEM-4.4 (Revised), page 1 of 2, in the amounts of \$5,206,694 and \$16,132,193, respectively, relate to the continuation of Allowance for Funds Used During Construction ("AFUDC") and the deferral of depreciation from the time Schahfer Unit 18 went into service until the time it was included in rate base. In the Commission's July 15, 1987 Order in Cause No. 38045, the Company was authorized to phase-in this unit into rate base. In the Commission's November 27, 1985 Order in Cause No. 37819, the Company was authorized to amortize these deferrals over the remaining life of Schahfer Unit 18. The amount of \$21,338,887 reflects the unamortized amount of Schahfer Unit 18 deferred charges at December 31, 2007.

Q90. ~~Q78.~~ Please explain the Prepaid Pension Asset on Petitioner's Exhibit LEM-4,4 (Revised) page 1 of 2.

A90. ~~A78.~~ The Prepaid Pension Asset on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2, reflects the electric portion of prepaid pension costs in the amount of \$25,705,004.

Q91. ~~Q79.~~ Please explain the Materials & Supplies on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2?

A91. ~~A79.~~ The Materials & Supplies on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2, reflects the balance of the electric materials and supplies at December 31, 2007 per the Company's books and records in the amount of ~~\$46,907,735~~ 46,907,735, updated for Sugar Creek materials and supplies in the amount of \$1,495,291, which reflects the working capital adjustment related to the acquisition of the Sugar Creek Facility.

Q92. ~~Q80.~~ Please explain the Production Fuel on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2?

A92. ~~A80.~~ The Production Fuel on Petitioner's Exhibit LEM-4,4 (Revised), page 1 of 2, reflects the balance of production fuel at December 31, 2007 per the Company's books and records in the amount of \$57,566,559.

VI. CAPITAL STRUCTURE

Q93. ~~Q81.~~ Please explain Petitioner's Exhibit LEM-5,5 (Revised).

A93. ~~A81.~~ Petitioner's Exhibit LEM-5,5 (Revised), page 1 of 3, shows the computation of the overall weighted cost of capital for NIPSCO. Column A shows the components of

capital, including common equity, long term debt, customer deposits, deferred income taxes, postretirement liability, and Post 1970 ITC. Column B shows the "as adjusted" amount for each component. Column C shows the percent each component represents of the total capitalization. Column D shows the cost for each component. Column E shows the weighted average cost for each component. The cost of Post-1970 ITC represents the weighted average cost of investor supplied capital, which is computed in the second table on Page 1 of 3 on Petitioner's Exhibit LEM-5.5 (Revised). The total of Column E of 8.348.37% is the Company's weighted cost of capital. Petitioner's Exhibit LEM-5.5 (Revised), page 2 of 3, shows the December 31, 2007 actual capital structure and the adjustments made to arrive at the capital structure reflected on page 1. Column B shows the actual December 31, 2007 balances. Columns C and D show the updates to capital structure. Column E shows the reference to these updates, the detail of which is discussed below. Column F shows the adjusted balance. Column G reflects the percent of the total capitalization for each component. Column H shows the cost for each component. Column I shows the weighted average cost for each component. Petitioner's Exhibit LEM-5.5 (Revised), Page 3 of 3, is a detailed schedule of long-term debt, reflecting actual debt outstanding at December 31, 2007 as well as debt issued in June 2008. Column A reflects the interest rate associated with each debt issue. The individual debt issues are listed in Column B. Columns C and D reflect the dates of issuance and dates of maturity, respectively. The principal amount outstanding is shown in Column E. Column F reflects the interest requirement, which is the principal amount

(Column E) multiplied by the interest rate (Column A). Column G reflects the overall cost of debt, which flows to page 1 of 3.

Q94. **Q82.** What cost rate has been utilized for Common Equity on Petitioner's Exhibit LEM-5 (Revised)?

A94. **A82.** The cost rate for Common Equity on Petitioner's Exhibit LEM-5,5 (Revised), page 1 of 3, is 12%. The cost rate was determined and provided by NIPSCO Witness Paul R. Moul.

Q95. **Q83.** What cost rate has been utilized for Long-Term Debt on Petitioner's Exhibit LEM-5 (Revised)?

A95. **A83.** The cost rate for Long-Term Debt on Petitioner's Exhibit LEM-5,5 (Revised), page 1 of 3, is 6.56%, which is based on the debt outstanding at December 31, 2007 plus debt issued in June 2008.—2008— The update for the June 2008 debt issue is shown on Petitioner's Exhibit LEM-5,5 (Revised), page 2 of 3, and is discussed below.

Q96. **Q84.** What cost rate has been utilized for Customer Deposits as shown on Petitioner's Exhibit LEM-5 (Revised)?

A96. **A84.** The cost rate for Customer Deposits on Petitioner's Exhibit LEM-5,5 (Revised), page 1 of 3, is 6%, which is the interest rate on customer deposits as provided for in the Commission's rules.

Q97. **Q85.** Please explain Post-Retirement Liability on Petitioner's Exhibit LEM-5 (Revised)?

A97. ~~A85.~~ The Post-Retirement Liability on Petitioner's Exhibit LEM-5 (Revised) reflects the Statement of Financial Accounting Standard No. 106 ("SFAS 106") OPEB accrual expense in excess of the cash basis or Pay-As-You-Go Method ("PAYGO"). In accordance with the Commission's June 11, 1997 Order in Cause No. 40688, the Commission found that, commencing February 1, 1998, NIPSCO was authorized to include its SFAS 106 expense in its cost of service for ratemaking purposes. Additionally, the Commission authorized NIPSCO to commence the amortization of the expense that had been deferred as a regulatory asset pursuant to the Commission's December 30, 1992 Order in Cause No. 39348. The Commission also found that the cumulative difference between SFAS 106 expense and the cash outlay for post-retirement benefits other than pensions should be treated as zero cost capital. I have computed this adjustment by starting with the SFAS 106 gross accrual amounts (which includes all of the expenses deferred in the regulatory asset prior to February 1, 1997), then reducing for amounts paid as calculated under the PAYGO, then reducing further by the unamortized balance of the regulatory asset, then finally reducing by the capitalized portion. In this fashion, the amount reflected as zero cost capital is essentially equivalent to the amount that would have been recorded as SFAS 106 expense in excess of the PAYGO since February 1, 1997, together with the amount of the original regulatory asset that has been amortized, all as provided for in the Commission's Order in Cause No. 40688.

Q98. ~~Q86.~~ What updates were made to the capital structure for Step One?

A98. ~~A86.~~ Adjustments CS-1, CS-2, ~~and CS-3~~ and CS-4 were made with respect to common equity, long-term debt, ~~and deferred taxes and retirement liability~~, respectively. These adjustments are shown on Petitioner's Exhibit LEM-5,5 (Revised), page 2 of 3, and are discussed below.

Q99. ~~Q87.~~ Please explain Adjustment CS-1 on Petitioner's Exhibit LEM-5,5 (Revised).

A99. ~~A87.~~ Adjustment CS-1 on Petitioner's Exhibit LEM-5 (Revised) is an increase (credit) in common equity in the amount of \$1,168,208, made to reflect the exclusion of Other Comprehensive Income ("OCI") from the December 31, 2007 balance. This adjustment to common equity is necessary as the OCI is related to the market impact of derivative activity which is non cash in nature. Mr. Moul provides further discussion of this item.

Q100. ~~Q88.~~ _____

Please explain Adjustment CS-2 on Petitioner's Exhibit LEM-5.5 (Revised).

A100. ~~A88.~~ Adjustment CS-2 on Petitioner's Exhibit LEM-5 (Revised) is an increase (credit) in long-term debt in the amount of \$160,000,000, made to reflect the long-term debt issued by NIPSCO to NiSource Finance Corporation in June 2008. This debt was issued as a replacement for the 2007 redemption of NIPSCO's preferred stock as well as scheduled maturities of medium-term notes. The Commission approved the issuance of these notes in its February 6, 2008 Order in Cause No. 43370. This issue consisted of two components, and the capital structure reflects the interest rate applicable to each portion of the debt issue, totaling \$160,000,000. NIPSCO Witness Vincent V. Rea discusses the financing and interest rate determination.

Q101. Q89. Please explain Adjustment CS-3 on Petitioner's Exhibit LEM-5.5 (Revised).

A101. ~~A89.~~ Adjustment CS-3 on Petitioner's Exhibit LEM-5 (Revised) is an increase (credit) to the capital structure in the amount of \$795,992 in order to exclude the deferred taxes related to the OCI adjustment to common equity for the derivative activity discussed previously.

Q102. Please explain Adjustment CS-4 on Petitioner's Exhibit LEM-5 (Revised).

A102. Adjustment CS-4 on Petitioner's Exhibit LEM-5 (Revised) corrects the zero cost capital component for SFAS 106 to account for the error in medical benefits expense (Adjustment OM-25) I described previously. These are amounts the Company incurred for medical benefits costs that should have been reflected as reductions in the SFAS 106 accrued liability rather than active employee medical benefits costs. When computing the

amount for SFAS 106 accruals to include in the capital structure at zero cost, the amounts actually paid for such benefits (the PAYGO amounts must be subtracted). The correction for this error increases the amount that was actually paid for retiree benefits and thereby reduces the Retirement Liability component of the capital structure by the same amount. As indicated previously, the total amount of the error was \$10,040,730, and so that is the amount by which zero cost capital is also reduced. Petitioner's Exhibit LEM-5 (Revised) , pages 1 and 2 of 3 have been revised to reflect a Total Company Capitalization amount of \$2,793,695,583 and Weighted Average Cost of 8.37%.

VII. TRACKER MECHANISMS

Q103. Q90. Is NIPSCO proposing any tracking mechanisms in this proceeding?

A103. A90. Yes, NIPSCO is proposing the continuation of its FAC, EERM, and Environmental Cost Recovery Mechanism ("ECRM") tracking mechanisms. As part of this rate case proceeding, NIPSCO seeks approval for a change in the frequency of the filing of its EERM to semi-annual from annual and for approval for use of the EERM to pass back to ratepayers the net proceeds realized through the sale of emissions allowances, as well as any costs incurred to purchase allowances. In addition to the continuation of these existing tracking mechanisms with the requested modifications, NIPSCO is proposing the RA tracking mechanism to provide for (1) recovery and pass-through of certain regional transmission organization costs and revenues; (2) recovery of purchased power costs; and (3) the allocation of net revenues from NIPSCO's off-system sales. As described previously in REV-8 and FP-5, NIPSCO proposes that 100% of future off-system sales

margins be passed back to the ratepayers up to \$15 million annually. NIPSCO requests that any off-system sales margins generated beyond the amount of \$15 million annually will be shared, with 80% going to ratepayers. In addition, as noted in Adjustment REV-10, the Company proposes that 100% of transmission revenues from certain MISO schedules be passed back to ratepayers via this RA mechanism. Mr. Crum further describes this mechanism. I describe the schedules that will be utilized for the proposed RA tracking mechanism below.

Q104. ~~Q91.~~ Please describe Petitioner's Exhibit LEM-10.

A104. ~~A91.~~ Petitioner's Exhibit LEM-10 shows the sample schedules proposed to be utilized with the proposed RA tracking mechanism. NIPSCO proposes that this mechanism be filed quarterly concurrent with the quarterly FAC filings. The RA is intended to be utilized to recover purchased power and capacity costs, all non-FAC MISO charges / (credits) and to pass through off-system sales net revenues. Petitioner's Exhibit LEM-10 contains sample schedules with hypothetical dollar amounts and allocation percentages for hypothetical dates in order to demonstrate how Petitioner proposes this mechanism will function. Petitioner proposes that a quarterly estimate be prepared in order to bill customers and that a reconciliation of costs recovered to actual costs incurred be performed in a subsequent quarter, much like the process used for the existing FAC mechanism. Petitioner's Exhibit LEM-10, page 1 of 9, is the summary page showing the estimated costs / (credits) to be included in the RA and the resulting factors to be billed to customers. Lines 1 and 2 show capacity purchases and MISO charges that are demand

allocated, respectively. Both of these line items will be allocated to NIPSCO's proposed rate schedules based on demand factors. Line 3 is the total of Lines 1 and 2. Lines 4, 5 and 6 show energy purchases, all other non-FAC MISO charges / (credits) and off-system sales net revenues, respectively. Each of these three line items will be allocated to NIPSCO's proposed rate schedules based on energy. Line 7 is the sum of the Lines 4, 5 and 6. Lines 8 through 23 show the allocation of demand allocated and energy allocated charges by rate. Lines 24 through 39 show the total combined charges plus the variance from previous periods. Line 39, column L shows the total net charges / (credits) to be billed to customers by rate schedule and column M reflects the factor for each rate schedule. Column N is the billing factor adjusted for URT and Adjusted Gross Income Tax. Petitioner's Exhibit LEM-10, pages 2 through 5 of 9, reflect the detail behind Page 1 of 9, Lines 1, 2, 4, 5, and 6, as described above. Petitioner's Exhibit LEM-10, page 6 of 9, shows the charges recovered for the quarter less the amount of prior period variance to be recovered, compared to actual charges for the quarter, and the new resulting variance. Petitioner's Exhibit LEM-10, page 7 of 9, shows the detailed reconciliation and allocation of actual costs based on demand and energy as explained above. Petitioner's Exhibit LEM-10, page 8 of 9, shows actual costs / (credits) by type. Petitioner's Exhibit LEM-10, page 9 of 9, shows a detailed list of MISO charge-types. For simplicity purposes, this reconciliation is shown for one of the three months in the quarter. The remaining two months would be shown on similar pages.

Q105. ~~Q92.~~ Please describe how the EERM and ECRM tracking mechanisms will be impacted upon the issuance of an Order in this proceeding.

A105. ~~A92.~~ Prior to the issuance of an Order in this proceeding, the ECRM and EERM tracker filings will be separated to delineate those costs and expenses that have been included in the requested revenue requirement in this proceeding from expenditures and operating expenses not reflected in the revenue requirement for this proceeding. Upon the issuance of an Order in this proceeding, new tariff tracker schedules will be utilized to remove the impact of the costs and expenses reflected in new rates to ensure that there is no duplication in revenue collection. These tracking mechanisms will continue to be utilized for future Qualified Pollution Control Property ("QPCP") not reflected in rate base and for future operating costs associated with QPCP expenditures, in accordance with the Commission's prior orders in Cause Nos. 42150 (11/26/2002) and 43188 (7/3/2007). In addition, Petitioner is requesting in this proceeding that these mechanisms be expanded to make them applicable for costs associated with additional and future environmental regulatory requirements and also requests that both tracker filings may be made on a semi-annual basis.

VIII. STEP TWO — SUGAR CREEK FACILITY

Q93. ~~Please explain the Company's proposed Step Two rate increase request associated with the recently acquired Sugar Creek generating facility?~~

A93. ~~On May 28, 2008 in Cause No. 43396, the Commission issued an order granting NIPSCO a Certificate of Public Convenience and Necessity ("CPCN") to acquire the Sugar Creek~~

~~generating facility (the "Sugar Creek Facility") ("CPCN Order"). NIPSCO acquired the equity interests in Sugar Creek Power Company, LLC on May 30, 2008. The prior owners of Sugar Creek committed the Sugar Creek Facility to the PJM Interconnection, LLC ("PJM") market through May 31, 2010. In the CPCN Order, the Commission found that the Sugar Creek Facility could not be deemed to be "in service" for regulatory purposes while it is committed to the PJM market. The Company is requesting authorization of a second adjustment (the "Step Two Adjustment") to NIPSCO's basic rates and charges that will be implemented when the Sugar Creek Facility is no longer committed to PJM and is dispatched into MISO.~~

Q94. ~~What adjustment to NIPSCO's rates is the Company proposing to reflect in the Step Two Adjustment?~~

A94. ~~The Step Two Adjustment will increase NIPSCO's rates to reflect the additional costs NIPSCO incurs to own and operate the Sugar Creek Facility for the benefit of NIPSCO's customers, including taxes and O&M expenses. NIPSCO also has a pending proceeding in Cause No. 43396 S-1 in which it is seeking authority to defer carrying charges and depreciation expense on its investment in the Sugar Creek Facility from the date of the acquisition through the date when a return on and of NIPSCO's investment in the Sugar~~

Creek Facility is reflected in NIPSCO's rates. NIPSCO has proposed that, if such deferral authority is granted, the Step Two Adjustment include an amortization of the deferred amounts as an above-the-line expense and inclusion of the unamortized amount in NIPSCO's rate base. The Step Two Adjustment will also include a return on NIPSCO's investment in the Sugar Creek Facility. Mr. Shambo addresses the policy and structure of the Step Two Adjustment.

Q95. Please summarize your testimony for the Step Two Adjustment.

A95. NIPSCO requires a net increase in base rate revenues of \$80,723,642 in the Step Two Adjustment to recover the revenue requirement associated with the Sugar Creek Facility. This amount is calculated to provide the opportunity to earn additional net operating income of \$30,619,764. Support for the Step Two Adjustment is presented in Petitioner's Exhibits LEM 6 through LEM 9.

Q96. Please describe the exhibits relating to Step Two.

A96. Petitioner's Exhibit LEM 6, page 1 of 2, is a statement of Sugar Creek net operating income for the test year ended December 31, 2007 on a pro forma basis and adjusted for the proposed revenue increase of \$80,723,642. Petitioner's Exhibit LEM 6, page 2 of 2, shows the calculation of the proposed Sugar Creek revenue increase. Petitioner's Exhibit LEM 7 consists of a separate page for each Sugar Creek income statement adjustment. Petitioner's Exhibit LEM 8, page 1 of 2, shows the Sugar Creek original cost rate base

and a summary of the proposed updates. ~~Petitioner's Exhibit LEM 8, page 2 of 2, shows the detail of the proposed updates.~~

~~Petitioner's Exhibit LEM 9, page 1 of 3, shows the computation of the overall weighted cost of capital for Step Two with the inclusion of additional adjustments as discussed below. Column A shows the components of capital, including common equity, long term debt, customer deposits, deferred income taxes, postretirement liability, and Post 1970 ITC. Column B shows the "as adjusted" amount for each component of capital, reflecting the Step One updates described earlier in my testimony and the Step Two updates, which are described later in my testimony. Column C reflects the percent each line item represents of the total capitalization. Column D reflects the cost for each component and Column E shows the weighted average cost for each line item. The total of Column E of 8.43% is the Company's weighted cost of capital, reflecting the Sugar Creek facility in rate base. Petitioner's Exhibit LEM 9, Page 2 of 3, shows the December 31, 2007 capital structure with adjustments. Column B shows the actual December 31, 2007 balances, Columns C and D reflect the updates to capital structure for Step Two. These updates are identified as SCCS 1 and SCCS 2 in Column E and are further discussed below. Column F shows the pro forma balance. Column G reflects the percent each line item represents of the total capitalization. Column H shows the cost for each component and Column I shows the weighted average cost for each line item. Petitioner's Exhibit LEM 9, Page 3 of 3, is a detailed schedule of long term debt, reflecting actual debt outstanding at December 31, 2007 as well as debt issued in June 2008 and anticipated debt issues~~

associated with the financing of the acquisition of the Sugar Creek facility. Column A reflects the interest rate associated with each debt issue. The individual debt issues are listed in Column B. Columns C and D reflect the dates of issuance and dates of maturity, respectively. The principal amount outstanding is shown in Column E. Column F reflects the interest requirement, which is the principal amount (Column E) multiplied times the interest rate (Column A). Column G reflects the overall cost of debt, which flows to page 1 of 3.

Q97. Please explain Adjustment SCOM 1 on Petitioner's Exhibit LEM-6, page 1 of 2.

A97. Adjustment SCOM 1 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to operating expenses in the amount of \$3,572,954 for the variable production expense required to operate the Sugar Creek Facility. Mr. Pack further describes the calculation of this adjustment.

Q98. Please explain Adjustment SCOM 2 on Petitioner's Exhibit LEM-6, page 1 of 2.

A98. Adjustment SCOM 2 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to operating expenses in the amount of \$5,815,467 for other O&M expenses, which consists of fixed operating expenses for the plant as well as property insurance related to the Sugar Creek Facility. Mr. Pack further describes the calculation of this adjustment.

Q99. Please explain Adjustment SCDA 1 on Petitioner's Exhibit LEM-6, page 1 of 2.

A99. Adjustment SCDA 1 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to electric operating expenses for \$11,236,857 for the annual depreciation/amortization

~~expense of the Sugar Creek Facility. This adjustment is based on the depreciation study~~
~~performed by NIPSCO Witness John Spanos.~~

Q100.

Please explain Adjustment SCDA 2 on Petitioner's Exhibit LEM-6, page 1 of 2.

A100. Adjustment SCDA 2 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to electric amortization expenses for \$2,694,743 for the amortization of the depreciation/amortization expense of the Sugar Creek Facility proposed to be deferred beginning June 1, 2008 through May 31, 2010. The amortization amount is calculated by adding the annual depreciation/amortization as described in Adjustment SCDA-1 for the two annual periods. I have reduced the amortization by \$4,500,000 (the annual depreciation on the Mitchell plant) for two years, pursuant to the FAC71 Settlement. This results in a total deferred amount of \$13,473,714. When amortized over a five-year period, the annual expense is \$2,694,743.

Q101. Please explain Adjustment SCDA 3 on Petitioner's Exhibit LEM-6, page 1 of 2.

A101. Adjustment SCDA 3 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to electric amortization expenses for \$8,529,686 for the amortization of the deferred carrying charges on the Sugar Creek facility. This amount represents the amount of carrying charges proposed to be deferred beginning June 1, 2008, calculated by multiplying the \$328,064,833 gross utility plant in service value by a rate of 6.5% for two years and amortized over a five-year period.

Q102. How did you calculate the utility plant in service value for the Sugar Creek Facility?

A102. NIPSCO actually paid \$329,672,739 to acquire Sugar Creek. However, I have deducted interest expense and materials and supplies inventory recorded on NIPSCO's books and records, as well as miscellaneous other current assets and liabilities because these

amounts should not be included in utility plant in service. Further adjustment may be required because the purchase agreement requires a true up for working capital. As soon as the information is available, Petitioner will true up the final purchase price, including the filing of amended exhibits, to appropriately reflect the correct amount for purposes of the rate base updates. This true up will likely change the materials and supplies inventory balance, which is described in Update SCRB-2.

Q103. Why are you using a 6.5% rate to calculate carrying charges and using a five year amortization period?

A103. That rate is consistent with the terms of the FAC71 Settlement as is the five year amortization period.

Q104. Please explain Adjustment SCOTX-1 on Petitioner's Exhibit LEM-6, page 1 of 2.

A104. Adjustment SCOTX-1 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to property taxes for \$1,132,243 for the Sugar Creek Facility. This amount was provided by Mr. O'Brien, who discusses it further. If this adjustment is not made, property tax expense will be understated.

Q105. Please explain Adjustment SCPF-1 on Petitioner's Exhibit LEM-6, page 1 of 2.

A105. Adjustment SCPF-1 on Petitioner's Exhibit LEM-6, page 1 of 2, shows the calculation of the increased revenue requirement for NIPSCO necessary to provide an 8.43% return on net original cost rate base of \$363,223,758. The increased revenue requirement is calculated by determining the requested increase in operating income. The requested

operating income increase is determined by applying the proposed rate of return of 8.43% to the net original cost rate base for Sugar Creek shown on page 2 of 2 of Petitioner's Exhibit LEM-6. The increase in operating income is then grossed up for the following taxes and fees: (a) Federal income taxes, (b) State income taxes, (c) URT, (d) Public Utility Fees, and (e) Uncollectible accounts. The proposed increase in revenue requirement is \$80,723,642.

Q106. Please explain Adjustment SCOM-3 on Petitioner's Exhibit LEM-6, page 1 of 2.

A106. Adjustment SCOM-3 on Petitioner's Exhibit LEM-6, page 1 of 2, reflects the additional uncollectible accounts expense on the revenue increase by multiplying the proposed increase in revenue requirement by the multiplier of 0.226593%, for an increase in expense of \$182,914 at the proposed rates level.

Q107. Please explain Adjustment SCOTX-2 on Petitioner's Exhibit LEM-6, page 1 of 2.

A107. Adjustment SCOTX-2 on Petitioner's Exhibit LEM-6, page 1 of 2, is a calculation of the Public Utility Fees applicable to the proposed increase in revenue requirement and is calculated by applying the 0.1204% rate to the proposed increase of \$80,723,642, resulting in an increase of \$97,191.

Q108. Please explain Adjustment SCOTX-3 on Petitioner's Exhibit LEM-6, page 1 of 2.

A108. Adjustment SCOTX-3 on Petitioner's Exhibit LEM-6, page 1 of 2, is a calculation of the URT applicable to the proposed increase in revenue requirement and is calculated by

| ~~applying the 1.4% rate to the proposed increase of \$80,723,642, resulting in an increase~~
| ~~of \$1,130,131.~~

| **Q109.**

~~Please explain Adjustment SCITX 1 on Petitioner's Exhibit LEM-6, page 1 of 2.~~

~~A109. Adjustment SCITX 1 on Petitioner's Exhibit LEM-6, page 1 of 2, is the calculation of the income taxes applicable to the proposed increase in net operating income. It is calculated by applying the federal and state income tax rates to the proposed increase in net operating income for federal and state income tax purposes, which results in increased expense of \$15,711,692.~~

~~Q110. Please explain Update SCRB 1 on Petitioner's Exhibit LEM-8, page 2 of 2.~~

~~A110. Update SCRB 1 on Petitioner's Exhibit LEM-8, page 2 of 2, is the update to increase (debit) plant in service in the amount of \$328,064,833 to reflect the plant acquired in the purchase of the Sugar Creek Facility. Messrs. Sweet and Shambo discuss the purchase of the Sugar Creek Facility.~~

~~Q111. Please explain Update SCRB 2 on Petitioner's Exhibit LEM-8, page 2 of 2.~~

~~A111. Update SCRB 2 on Petitioner's Exhibit LEM-8, page 2 of 2, is the update to increase (debit) materials and supplies in the amount of \$1,510,497 to reflect the inventory acquired as part of the purchase of the Sugar Creek Facility. Mr. Sweet discusses the purchase of the Sugar Creek Facility. This inventory balance is subject to change following the final working capital true-up described above.~~

~~Q112. Please explain Update SCRB 3 on Petitioner's Exhibit LEM-8, page 2 of 2.~~

~~A112. Update SCRB 3 on Petitioner's Exhibit LEM-8, page 2 of 2, is the update to increase (credit) accumulated depreciation and amortization for \$22,473,714 for the two years of~~

depreciation/amortization expense for the Sugar Creek Facility (\$11,236,857) per year as described in Adjustment SCDA-1) that will have been recorded as of June 1, 2010, when the commitment to the PJM market is scheduled to expire.

Q113. Please explain ~~Update SCRB-4 on Petitioner's Exhibit LEM-8, page 2 of 2.~~

~~A113. Update SCRB-4 on Petitioner's Exhibit LEM-8, page 2 of 2, is the update to increase (debit) deferred charges for \$13,473,714 for the deferral of the accumulated depreciation and amortization for two years as described in Update SCRB-3, net of the \$4,500,000 annual exclusion deemed to be representative of the annual depreciation expense for the Mitchell generating facility. Such deferral treatment is currently pending before the Commission in Cause No. 43396 S-1.~~

Q114. Please explain ~~Update SCRB-5 on Petitioner's Exhibit LEM-8, page 2 of 2.~~

~~A114. Update SCRB-5 on Petitioner's Exhibit LEM-8, page 2 of 2, is the update to increase (debit) deferred charges for \$42,648,428 for the carrying charges on the Sugar Creek Facility for the two year period of June 1, 2008 to May 31, 2010. This amount represents the amount of carrying charges to be deferred beginning June 1, 2008 through May 31, 2010, calculated by multiplying the \$328,064,833 purchase price of the facility by a rate of 6.5% for each year. Such deferral treatment is currently pending before the Commission in Cause No. 43396 S-1.~~

Q115. What updates were made to the Capital Structure for the Step Two Adjustment?

A115. ~~In addition to the changes to the capital structure described in Step One, Adjustments SCCS 1 and SCCS 2 were made with respect to common equity and long term debt, respectively, related to the funding of the acquisition of the Sugar Creek Facility. These adjustments are shown on Petitioner's Exhibit LEM 9, page 2 of 3, and are discussed below.~~

Q116. Please explain Update SCCS 1 on Petitioner's Exhibit LEM 9, page 2 of 3.

A116. ~~Update SCCS 1 on Petitioner's Exhibit LEM 9, page 2 of 3, is an increase (credit) in common equity of \$140,000,000, made to reflect the expected earnings to be retained by the Company and used to complete the funding of the Sugar Creek acquisition.~~

Q117. Please explain Update SCCS 2 on Petitioner's Exhibit LEM 9, page 2 of 3.

A117. ~~Update SCCS 2 on Petitioner's Exhibit LEM 9, page 2 of 3, is an increase (credit) in long term debt of \$120,000,000, made to reflect the anticipated issue of intercompany long term debt by NIPSCO to NiSource Finance Corporation, pending approval by the Commission of a financing petition filed August 26, 2008. This debt issue will be used as partial funding of the Sugar Creek acquisition and will replace temporarily used money pool financing. Mr. Rea discusses the financing and interest rate determination.~~

Q118. What cost rate has been utilized for Common Equity on Petitioner's Exhibit LEM-9?

A118. ~~The cost rate for Common Equity on Petitioner's Exhibit LEM 9, page 1 of 3, is 12%.~~
~~The cost rate was determined and provided by Mr. Moul.~~

Q119. ~~What cost rate has been utilized for Long-Term Debt on Petitioner's Exhibit LEM-9?~~

A119. ~~The cost rate for Long-Term Debt on Petitioner's Exhibit LEM-9, page 1 of 3, is 6.55%, which is based on the actual cost of debt outstanding at December 31, 2007 plus the cost of debt issued in June 2008, plus the estimated cost of debt to be issued related to the financing of the Sugar Creek acquisition as described above. The update for this anticipated debt issue is shown in Petitioner's Exhibit LEM-9, page 3 of 3.~~

Q106. ~~Q120. Does this conclude your prepared direct testimony?~~

A106. ~~A120. Yes, it does.~~

VERIFICATION

I, Linda E. Miller, Executive Director, Rates and Regulatory Finance for NiSource Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Linda E. Miller

Date: ~~August~~ December 19, 2008

INDS01 NKK 1055761v17

Revised

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

LINDA E. MILLER

EXECUTIVE DIRECTOR, RATES AND REGULATORY FINANCE

SPONSORING PETITIONER'S EXHIBITS LEM-2 THROUGH LEM-5 and LEM-10

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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VERIFIED DIRECT TESTIMONY

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EXECUTIVE DIRECTOR, RATES AND REGULATORY FINANCE

SPONSORING PETITIONER'S EXHIBITS LEM-2 THROUGH LEM-5 and LEM-10

VERIFIED DIRECT TESTIMONY OF LINDA E. MILLER

1 **Q1. Please state your name, business address and job title.**

2 A1. My name is Linda E. Miller. My business address is 801 East 86th Avenue, Merrillville,
3 Indiana 46410. I am employed by NiSource Corporate Services ("NCS"), which is a
4 subsidiary of NiSource Inc. ("NiSource"). My current position is Executive Director of
5 Rates and Regulatory Finance for the Northern Indiana Energy business unit, which is
6 comprised of Northern Indiana Public Service Company ("NIPSCO" or the "Company"),
7 Northern Indiana Fuel and Light Company, Inc, and Kokomo Gas and Fuel Company, all
8 of which are subsidiaries of NiSource. I am submitting this testimony on behalf of
9 NIPSCO.

10 **Q2. Please summarize your employment and educational background.**

11 A2. I graduated from the College of the Southwest with a bachelor's degree in business,
12 majoring in accounting in 1985. I am a Certified Public Accountant in Indiana. I have
13 held various positions during my career, including Assistant Comptroller for a regional
14 bank and Controller for a regional newspaper. In 1999, I accepted a position with
15 NIPSCO's business planning department. On January 1, 2001, I became an employee of
16 NCS. I was promoted to Segment Controller for the Northern Indiana Energy business
17 unit in August 2002. In February 2008, I became Director of Rates and Regulatory
18 Finance. In June 2008, I was named Executive Director of Rates and Regulatory
19 Finance.

1 **Q3. What are your responsibilities as Executive Director of Rates and Regulatory**
2 **Finance?**

3 A3. For the Northern Indiana Energy business unit, I have overall responsibility for rate and
4 contract administration, revenue requirements, rate design, electric and gas rates, rules,
5 regulations and contract filings with the Indiana Utility Regulatory Commission ("IURC"
6 or "Commission"), the preparation and filing of all electric and gas cost adjustment
7 filings with the IURC, the preparation and coordination of other regulatory filings,
8 implementation and compliance with state and federal regulatory orders, and all
9 regulatory finance matters.

10 **Q4. Have you previously testified before this Commission?**

11 A4. Yes, on many occasions.

12 **Q5. What is the purpose of your revised direct testimony in this proceeding?**

13 A5. The purpose of my revised direct testimony is to present rate base, capital structure and
14 weighted cost of capital, and results of operations during the test year and on a pro forma
15 basis at both present and proposed rates. I will also describe NIPSCO's proposed
16 tracking mechanisms and changes to existing tracking mechanisms. Other NIPSCO
17 witnesses also address the Company's proposed tracking mechanisms.

18 **Q6. Please summarize your testimony.**

19 A6. As explained by NIPSCO Witness Frank A. Shambo, the Company proposes to remove
20 the cost of fuel and associated taxes from base rates. The Company proposes to recover
21 through base rates the gross margin (total revenues less fuel, purchased power and

1 associated taxes) of \$962,393,192. NIPSCO requests an increase in base rates calculated
2 to produce additional gross margin of \$85,744,828 based on test year pro forma levels
3 This amount is calculated to provide the opportunity to earn net operating income of
4 \$223,095,808. Support for this request is presented in Petitioner's Exhibits LEM-2
5 (Revised) through LEM-5 (Revised).

6 **Q7. What exhibits are you sponsoring and were the exhibits prepared by you or under**
7 **your supervision and direction?**

8 A7. I am sponsoring Petitioner's Exhibits LEM-2 (Revised) through LEM-5 (Revised) and
9 LEM-10, all of which were prepared by me or under my supervision and direction.

10 **Q8. Why has your direct testimony been revised from when it was originally prefiled?**

11 A8. The purpose of the revisions to my testimony is to provide the revenue requirements
12 associated with the Sugar Creek generating facility ("Sugar Creek Facility"), which
13 NIPSCO now proposes be included in Petitioner's rate base immediately. My revised
14 testimony also supports an adjustment for a correction made in 2008 which reduces 2007
15 medical benefits expense due to an error that was discovered after the Case-In-Chief was
16 filed. This latter adjustment also has a corresponding impact on Petitioner's capital
17 structure.

18 **Q9. Please describe the reason for the change associated with the Sugar Creek Facility.**

19 A9. On May 28, 2008 in Cause No. 43396, the Commission issued an order granting NIPSCO
20 a Certificate of Public Convenience and Necessity ("CPCN") to acquire the Sugar Creek
21 Facility ("CPCN Order"). NIPSCO acquired the equity interests in Sugar Creek Power

1 Company, LLC on May 30, 2008. The prior owners of Sugar Creek had committed the
2 Sugar Creek Facility to the PJM Interconnection, LLC ("PJM") market through May 31,
3 2010. In the CPCN Order, the Commission found that the Sugar Creek Facility could not
4 be deemed to be "in service" for regulatory purposes while it is committed to the PJM
5 market. Therefore, in its Case-In-Chief as originally filed, NIPSCO requested
6 authorization of a second adjustment (the "Step Two Adjustment") to NIPSCO's basic
7 rates and charges to be implemented when the Sugar Creek Facility would be no longer
8 committed to PJM and instead dispatchable into the Midwest Independent Transmission
9 System Operator, Inc. ("Midwest ISO"). Subsequent to the filing of its Case-In-Chief,
10 NIPSCO has negotiated an agreement to terminate the commitment of Sugar Creek into
11 PJM and as of December 1, 2008, Sugar Creek is an Internal Designated Network
12 Resource in Midwest ISO. As a result, the originally proposed Step Two Adjustment is
13 now being combined into Step One. In the revised testimony, NIPSCO is presenting a
14 revised revenue requirement, which includes the Sugar Creek Facility in rate base and
15 operation and maintenance ("O&M") and depreciation/amortization expenses associated
16 with the Sugar Creek Facility in pro forma results of operations.

17 **Q10. Please describe the reason for the change associated with medical benefits expense.**

18 A10. Subsequent to the filing of NIPSCO's Case-In-Chief, the Company discovered that
19 certain medical benefits expenses had been coded incorrectly resulting in an error on the
20 Company's books and records. Certain medical benefits costs that had been incurred for
21 retired workers had actually been recorded as if they had been incurred for the current
22 workforce. The effect of the error was to overstate medical benefits expense and

1 overstate the accrued liability for post-retirement benefits other than pensions pursuant to
2 Statement of Financial Accounting Standard 106 ("SFAS 106"). Making this correction
3 impacts both the pro forma level of medical benefits expense and the component of the
4 capital structure for the amount of SFAS 106 accrual to be recognized at zero cost.

5 **Q11. Please describe the exhibits.**

6 A11. Petitioner's Exhibit LEM-2 (Revised), pages 1 of 4 and 2 of 4, is a statement of
7 NIPSCO's net operating income for the test year ended December 31, 2007 shown on an
8 actual basis, and with pro forma adjustments at current and proposed rates; Petitioner's
9 Exhibit LEM-2 (Revised), page 3 of 4, shows the calculation of the proposed revenue
10 increase; and Petitioner's Exhibit LEM-2 (Revised), page 4 of 4, is a reconciliation of the
11 requested revenue increase. Petitioner's Exhibit LEM-3 (Revised) consists of a separate
12 page for each income statement adjustment, including those that were reflected in the
13 original case-in-chief filing and the new adjustments for Sugar Creek and the medical
14 benefits correction, both of which I describe further later in my testimony. Petitioner's
15 Exhibit LEM-4 (Revised), page 1 of 2, shows the original cost rate base and a summary
16 of proposed updates, including Sugar Creek; Petitioner's Exhibit LEM-4 (Revised), page
17 2 of 2, shows the detail of the proposed updates. Petitioner's Exhibit LEM-5 (Revised),
18 page 1 of 3, is the capital structure and overall weighted cost of capital; Petitioner's
19 Exhibit LEM-5 (Revised), page 2 of 3, shows the capital structure updates, including the
20 change to the capital structure related to the overstatement of medical benefits expense
21 that I will explain further later in my testimony, and Petitioner's Exhibit LEM-5
22 (Revised), page 3 of 3, is a schedule of outstanding long-term debt (unchanged).

1 Petitioner's Exhibit LEM-10 shows the sample schedules proposed to be utilized with the
2 proposed Reliability Adjustment ("RA") tracking mechanism and is unchanged from the
3 original filing. Petitioner's Exhibit LEM-6 through LEM-9 in the original filing have
4 been deleted because they related to NIPSCO's former Step Two Adjustment proposal.

5 **I. STATEMENT OF OPERATING INCOME**

6 **Q12. Please explain Petitioner's Exhibit LEM-2 (Revised).**

7 A12. Petitioner's Exhibit LEM-2 (Revised), pages 1 of 4 and 2 of 4, is the Statement of
8 Operating Income for the twelve months ended December 31, 2007 shown on an actual
9 basis, and with pro forma adjustments at current and proposed rates. Column B shows
10 the actual results for the twelve months ended December 31, 2007. Column C shows the
11 pro forma adjustments made for the fixed, known and measurable changes to reflect
12 ongoing operations levels at current rates. A detailed listing of the pro forma adjustments
13 is shown on Petitioner's Exhibit LEM-3 (Revised) and each is discussed later in my
14 testimony. Column D shows the reference to each of the detailed adjustments. Column
15 E shows the pro forma levels at current rates. Column F shows the increases necessary to
16 produce the required levels of operating revenue and income. Column G shows the
17 reference to each of the line items in the proposed increase in operating revenue and
18 income. Column H shows the pro forma statement of operating revenue and income at
19 proposed rates. Petitioner's Exhibit LEM-2 (Revised), Page 3 of 4, shows the calculation
20 of the proposed base rate change to produce the gross margin revenue increase of
21 \$85,744,828. Petitioner's Exhibit LEM-2 (Revised), Page 4 of 4, shows a reconciliation
22 of the requested increase.

II. REVENUE ADJUSTMENTS

Q13. Please explain Adjustment REV-1 on Petitioner's Exhibit LEM-2 (Revised).

A13. Adjustment REV-1 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit) operating revenues in the amount of \$14,604,146 for warmer than normal weather during the 2007 test year. NIPSCO Witness William Gresham discusses the methodology utilized to determine the \$14,604,146 operating revenue adjustment. The dollar amount of the adjustment was calculated by applying Mr. Gresham's MWH adjustments to the applicable rate for each month in the May through October Cooling Degree Days season. This calculation is further detailed in the workpapers to be filed in this proceeding. This adjustment was made to normalize the test year revenues to exclude the variable impact of weather. If this adjustment is not included, test year operating revenues would be overstated. A corresponding adjustment was made to fuel expense in Adjustment FP-1 on Petitioner's Exhibit LEM-2 (Revised) below.

Q14. Please explain Adjustment REV-2 on Petitioner's Exhibit LEM-2 (Revised).

A14. Adjustment REV-2 on Petitioner's Exhibit LEM-2 (Revised) is to increase (credit) operating revenues in the amount of \$1,432,424 for the imputation of customer revenue for those customers on Economic Development Rider ("EDR") rates. The customers on these EDR rates receive a discount from the tariff rate level and, since NIPSCO is requesting a rate increase in this proceeding, this discounted amount is required by the tariff to be imputed as an increase (credit) to the test year operating revenues. This adjustment amount was obtained by querying the Customer Information System ("CIS") used to bill customers. The CIS produced a report itemizing the discount given to each

1 customer for each month in the test year, which was used to determine the sum of
2 \$1,432,424. If this adjustment is not included, test year operating revenues would be
3 understated.

4 **Q15. Please explain Adjustment REV-3 on Petitioner's Exhibit LEM-2 (Revised).**

5 A15. Adjustment REV-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (credit)
6 operating revenues in the amount of \$80,082,674 to account for the expiration of special
7 contract rates applicable to certain large industrial customers. These special contracts
8 provide significant discounts from tariff rates. The adjustment is primarily related to
9 contracts that are set to expire six months following the implementation of the new basic
10 rates and charges approved in this proceeding in accordance with the terms of the
11 Commission Orders approving the contracts or in accordance with the terms of the
12 contracts themselves. While this adjustment is outside the adjustment period to be used
13 in this Cause, I have calculated the adjustment so as to eliminate the discount. Mr.
14 Shambo further discusses the revenue adjustment for this group of customers. If this
15 adjustment is not included, test year operating revenues would be understated.

16 **Q16. Please explain Adjustment REV-4 on Petitioner's Exhibit LEM-2 (Revised).**

17 A16. Adjustment REV-4 on Petitioner's Exhibit LEM-2 (Revised) is to increase (credit)
18 operating revenues in the amount of \$33,500,000 due to a settlement agreement approved
19 by the Commission's January 30, 2008 Order in Cause No. 38706-FAC71 requiring a
20 refund to customers (the "FAC71 Settlement"). In September 2007, operating revenues
21 were reduced (debited) by \$33,500,000 and a reserve established for return to customers

1 and payment of legal fees of certain parties to the FAC71 Settlement. The \$33,500,000
2 refund related to certain purchased power costs, in accordance with the FAC71
3 Settlement. The \$33,500,000 entry was made as a one-time reduction to revenue during
4 the test year. In order to properly reflect the 2007 test year operating revenues at present
5 rates, this nonrecurring entry is required to be adjusted. If this adjustment is not included,
6 test year operating revenues would be understated.

7 **Q17. Please explain Adjustment REV-5 on Petitioner's Exhibit LEM-2 (Revised).**

8 A17. Adjustment REV-5 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit)
9 operating revenues in the amount of \$2,203,737 to eliminate the test year impact of
10 entries made to reverse a reserve balance previously established related to financial
11 transactions. The reserve had been established in the amount of net "losses" on financial
12 transactions, pending approval of the treatment of these transactions via the fuel
13 adjustment clause ("FAC") mechanism. The FAC71 Settlement (previously discussed in
14 Adjustment REV-4) resolved this issue as well. As a result, this reserve was reversed and
15 a full reserve for the amount of the FAC71 Settlement was established, reducing
16 revenues. If this adjustment is not included, test year operating revenues would be
17 overstated.

18 **Q18. Please explain Adjustment REV-6 on Petitioner's Exhibit LEM-2 (Revised).**

19 A18. Adjustment REV-6 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit)
20 operating revenues in the amount of \$804,136 for a particular group of customers in the
21 metal melting business. For this group of customers, the 2007 test year revenues

1 reflected operating volumes higher than that contractually allowed. This level of
2 volumes above the contract volumes was not anticipated and will not be permitted in the
3 future. Therefore, this adjustment is made in order to reflect test year revenues at a level
4 equivalent to the level of revenues that would have been received had this group of
5 customers not been operating above contract levels. If this adjustment is not included,
6 test year operating revenues would be overstated. Mr. Shambo further discusses the
7 adjustment for this group of customers. A corresponding adjustment was made to fuel
8 expense in Adjustment FP-2 on Petitioners Exhibit LEM-2 (Revised) below.

9 **Q19. Please explain Adjustment REV-7 on Petitioner's Exhibit LEM-2 (Revised).**

10 A19. Adjustment REV-7 on Petitioner's Exhibit LEM-2 (Revised) is to increase (credit)
11 operating revenues in the amount of \$10,955,615 for a one-time unbilled revenue
12 correction recorded in 2007 but related to prior periods. This entry was made as a result
13 of a change in the methodology used to calculate unbilled revenues and receivables. This
14 change resulted in a one-time adjusting entry to the income statement and balance sheet
15 in the test year, reducing revenues. Unbilled revenues and receivables have no impact on
16 customer bills. Unbilled amounts are calculated based on an estimate of the amount of
17 volumes that have not yet been billed at the end of the test year. During the review of the
18 December 2007 closing of the financial books, it was determined that the December 31,
19 2007 estimate of unbilled volumes was higher than it should be, and that therefore, the
20 unbilled receivable balance would be overstated, if not adjusted. The adjusting entry to
21 correct for this was a credit (reduction) to receivables and a debit (reduction) to revenues,
22 made to the December 2007 books, prior to issuing final financial statements. The

1 analysis of the unbilled volumes revealed a need to revise the methodology being used
2 and also revealed that the method that had been in use affected revenues and receivables
3 for prior years as well as 2007. Therefore, the correcting entry, although made in 2007,
4 affected prior periods as well. Adjustment REV-7 adds back the amount of revenue
5 reduction that relates to periods prior to the test year. The amounts related to prior
6 periods, but recorded in the test year are adjusted out in order to eliminate the impact to
7 the test year operating income statement. If this adjustment is not included, test year
8 operating revenues would be understated. NIPSCO Witness Mitchell E. Hershberger
9 further discusses the calculation of the unbilled correcting entry.

10 **Q20. Please explain Adjustment REV-8 on Petitioner's Exhibit LEM-2 (Revised).**

11 A20. Adjustment REV-8 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit)
12 operating revenues in the amount of \$50,400,058 for off-system sales revenues. This
13 amount represents the total amount of off-system sales revenues realized in the test year.
14 This adjustment is required because in this proceeding, Petitioner proposes that 100% of
15 future off-system sales margins be passed back to the ratepayers up to \$15 million
16 annually. NIPSCO requests that any off-system sales margins generated beyond the
17 amount of \$15 million annually will be shared, with 80% going to ratepayers. Petitioner
18 is proposing that this be accomplished via the proposed RA tracking mechanism, which is
19 described later in my testimony. Mr. Shambo further discusses this proposal and
20 NIPSCO Witness Curtis Crum describes this mechanism. If this adjustment is not
21 included, operating revenues would be overstated. A corresponding adjustment for the

1 fuel and purchased power costs associated with the 2007 off-system sales revenues is
2 made in Adjustment FP-5 on Petitioner's Exhibit LEM-2 (Revised) below.

3 **Q21. Please explain Adjustment REV-9 on Petitioner's Exhibit LEM-2 (Revised).**

4 A21. Adjustment REV-9 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit)
5 operating revenues in the amount of \$11,790,599 for revenues generated through the
6 sales of emissions allowances. Petitioner proposes that in the future when such sales
7 arise, the net proceeds of such sales will be passed back to the ratepayers via NIPSCO's
8 existing Environmental Expense Recovery Mechanism ("EERM"). Mr. Shambo further
9 discusses this proposal. If this adjustment is not included, test year operating revenues
10 would be overstated.

11 **Q22. Please explain Adjustment REV-10 on Petitioner's Exhibit LEM-2 (Revised).**

12 A22. Adjustment REV-10 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (debit)
13 operating revenues in the amount of \$4,726,034 for 2007 transmission revenues from the
14 Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO")
15 Schedules 7 and 8 and the revenues from MISO Schedules 1 and 2 associated with
16 Schedules 7 and 8. This adjustment is required due to the fact that, in this proceeding,
17 Petitioner proposes that 100% of future transmission revenues from the aforementioned
18 MISO schedules be passed back to ratepayers via the RA mechanism mentioned
19 previously and described later in my testimony. Mr. Shambo further discusses this
20 proposal. Mr. Crum further describes this mechanism. If this adjustment is not included,
21 test year operating revenues would be overstated.

1 **III. EXPENSE ADJUSTMENTS**

2 **A. Fuel and Purchased Power Expense Adjustments**

3 **Q23. Please explain Adjustment FP-1 on Petitioner's Exhibit LEM-2 (Revised).**

4 A23. Adjustment FP-1 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (credit) test year
5 operating expenses in the amount of \$3,683,450 to decrease fuel and purchased power
6 costs associated with the operating revenue adjustment for weather normalization as
7 outlined in Adjustment REV-1. The dollar amount of this adjustment was calculated by
8 applying the base fuel amount of 22.556 mills/kwh to Mr. Gresham's adjustment of
9 163,303 MWH. If this adjustment is not included, the test year operating expenses would
10 be overstated.

11 **Q24. Please explain Adjustment FP-2 on Petitioner's Exhibit LEM-2 (Revised).**

12 A24. Adjustment FP-2 on Petitioner's Exhibit LEM-2 (Revised) is to reduce (credit) test year
13 operating expenses in the amount of \$628,813 to decrease fuel costs related to the group
14 of customers described previously with respect to Adjustment REV-6. If this adjustment
15 is not included, test year operating expenses would be overstated.

16 **Q25. Please explain Adjustment FP-3 on Petitioner's Exhibit LEM-2 (Revised).**

17 A25. Adjustment FP-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
18 operating expenses in the amount of \$100,891 related to fuel handling expenses. It was
19 discovered that mobile fuel handling equipment depreciation had continued to be charged
20 to the D.H. Mitchell Generating Station ("Mitchell"), despite the fact that the coal-fired
21 units at this station ceased generating in 2002. This depreciation was related to coal

1 handling equipment originally utilized at Mitchell. It was determined that the equipment
2 had been physically transferred to the R. M. Schahfer and Michigan City Generating
3 Stations for use but the corresponding transfer on the Company's books and records was
4 not made. Because fuel handling charges are recorded by generating station, the Mitchell
5 fuel handling account (balance sheet account 152) continued to accumulate these charges.
6 Normally, fuel handling charges are accumulated in balance sheet account 152 and
7 cleared to operating expenses in relation to the coal burned during generation. Because
8 Mitchell was not generating, the amounts were never cleared to expense. In March, 2008
9 the general accounting department corrected the distribution of fuel handling depreciation
10 that should have been charged to the other generating stations (where the equipment was
11 located and being operated). This correction amounted to \$605,349. These amounts will
12 be cleared to fuel operating expenses on a going forward basis. The correction relates to
13 a six (6) year period, 2002 through 2007. As a result, I have calculated my adjustment to
14 reflect one sixth (1/6) of the adjustment or \$100,891 that would have been included in
15 fuel expense during the 2007 test year. If this adjustment is not included, test year
16 operating expenses would be understated.

17 **Q26. Please explain Adjustment FP-4 on Petitioner's Exhibit LEM-2 (Revised).**

18 A26. Adjustment FP-4 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
19 operating expenses in the amount of \$840,335 for the increase in the cost of diesel fuel
20 used in the fuel handling equipment in the generating stations. This adjustment is
21 necessary due to the increasing cost of diesel fuel. The amount of the adjustment was
22 calculated by multiplying the quantity of diesel fuel purchased in the test year (479,319

1 gallons) times a per gallon rate (\$4.032) based on the latest vendor invoice and
2 comparing the result of \$1,932,614 to the total amount spent on diesel fuel in the
3 generating stations during the test year, per the financial books and records, which was
4 \$1,092,279. The difference between the \$1,932,614 and the \$1,092,279 is the adjustment
5 amount of \$840,335. If this adjustment is not included, test year operating expenses
6 would be understated.

7 **Q27. Please explain Adjustment FP-5 on Petitioner's Exhibit LEM-2 (Revised).**

8 A27. Adjustment FP-5 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year
9 operating expenses in the amount of \$21,285,492 related to Adjustment REV-8. As
10 described previously, this adjustment is due to the fact that, in this proceeding, Petitioner
11 will be proposing that 100% of future off-system sales margins be passed back to the
12 ratepayers up to \$15 million annually. NIPSCO requests that any off-system sales
13 margins generated beyond the amount of \$15 million annually will be shared, with 80%
14 flowed to ratepayers. Petitioner is proposing that this be accomplished via the RA
15 mechanism mentioned previously and described later in my testimony. Mr. Crum also
16 describes this mechanism. If this adjustment is not included, test year operating expenses
17 would be overstated.

18 **B. Operating Expense Adjustments**

19 **Q28. Please explain Adjustment OM-1 on Petitioner's Exhibit LEM-2 (Revised).**

20 A28. Adjustment OM-1 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
21 operating expenses in the amount of \$1,006,664 for an increase in contract labor used by

1 the Generation Department. The Generation Department contracts with outside
2 companies to provide labor for many projects. NIPSCO Witness Phillip W. Pack further
3 discusses this adjustment. If this adjustment is not made, test year operating expenses
4 would be understated.

5 **Q29. Please explain Adjustment OM-2 on Petitioner's Exhibit LEM-2 (Revised).**

6 A29. Adjustment OM-2 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
7 operating expenses in the amount of \$4,001,238 related to the variable costs required to
8 operate the Company's generating facilities during the test year. This adjustment is based
9 on normalizing test year expenses for unusual periods of generating unit outages. Mr.
10 Sweet discusses how this calculation was made. If this adjustment is not included, test
11 year operating expenses would be understated.

12 **Q30. Please explain Adjustment OM-3 on Petitioner's Exhibit LEM-2 (Revised).**

13 A30. Adjustment OM-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
14 operating expenses in the amount of \$5,762,558 related to pension expense. Pension
15 calculations are determined by the Company's actuary, Hewitt and Associates, utilizing a
16 number of assumptions including discount rate, life expectancy and return on assets.
17 These factors can and do lead to fluctuations in the level of pension costs from year to
18 year. Pension costs have been highly volatile in recent years, with the range from 2003 to
19 the present varying by nearly \$50 million. To mitigate and normalize this volatility, I
20 calculated a five-year average of pension expense. This calculation leads to a pro forma
21 level of pension cost equaling \$2,139,542 (debit). After allocating to electric using the

1 established common allocation ratios, which are discussed by Mr. Hershberger, the 5-
2 year electric average is \$1,479,493. After deducting the portion capitalized, the 5-year
3 electric average expense is \$1,122,491. The 2007 actual was a credit of \$8,844,269 and
4 the amount allocated to electric was a credit of \$6,115,812. After deducting for the
5 portion capitalized, the 2007 actual electric expense was a credit of \$4,640,067. The 5-
6 year average electric expense of \$1,122,491 as compared to the 2007 electric credit of
7 \$4,640,067 results in a required increase (debit) adjustment of \$5,762,558. NIPSCO
8 Witness Robert D. Campbell further discusses the company's pension plans. If this
9 adjustment is not included, test year operating expenses would be understated.

10 **Q31. Please explain Adjustment OM-4 on Petitioner's Exhibit LEM-2 (Revised).**

11 A31. Adjustment OM-4 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
12 operating expenses in the amount of \$5,762,460 related to other post retirement employee
13 benefits ("OPEB") expense. OPEB calculations are determined by the Company's
14 actuary, Hewitt and Associates. The 2008 OPEB expense, as calculated by the actuary,
15 was allocated to electric using NIPSCO's common allocation ratios, and was then
16 compared to the actual 2007 electric portion of OPEB expense in the test year to
17 determine the amount of this pro forma adjustment. Unlike the pension expense
18 described above, OPEB is not subject to market fluctuations, and therefore the 2008
19 estimate calculated by Hewitt and Associates is believed to be a representative level of
20 OPEB expense. If this adjustment is not included, test year operating expenses would be
21 understated.

1 **Q32. Please explain Adjustment OM-5 on Petitioner's Exhibit LEM-2 (Revised).**

2 A32. Adjustment OM-5 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
3 operating expenses in the amount of \$5,083,259 related to employee wage increases. The
4 Company currently has in effect for its physical and clerical bargaining unit employees,
5 contracts effective June 1, 2004 and extending through May 31, 2009. In accordance
6 with those contracts, wage rates increase at the end of each calendar year from 2004
7 through 2008. The 2007 year end wage rate increase was 3%; wages will increase again
8 by 3% at the end of 2008. I have adjusted for the effect of the employee wage increase
9 that took effect upon the conclusion of the test year and then also adjusted for the
10 increase that will take effect 12 months thereafter at the end of 2008. The 2007
11 adjustments for the physical and clerical employees are \$3,311,418 and \$562,924,
12 respectively. The 2008 adjustments are \$3,410,760 and \$579,812, respectively. The
13 non-bargaining unit employees of NIPSCO receive wage increases on March 1 of each
14 year. In order to annualize the 2007 test year expense, the wages for the January and
15 February, 2007 period were increased by approximately 3% resulting in \$239,364. In
16 addition, the non-bargaining unit employees of NIPSCO received a 3.25% increase
17 effective March 1, 2008. In order to adjust for the 2008 wage increase, the normalized
18 wages for 2007 were increased by 3.25% resulting in an increase of \$1,584,744. The
19 total increase for the non-bargaining unit and bargaining unit wage increase adjustments
20 resulted in an increase of \$9,689,022, which was then allocated to electric, using the
21 established common allocation ratios, net of amounts capitalized, resulting in an electric

1 operating expense increase of \$5,083,259. If this adjustment is not included, test year
2 operating expenses would be understated.

3 **Q33. Please explain Adjustment OM-6 on Petitioner's Exhibit LEM-2 (Revised).**

4 A33. Adjustment OM-6 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
5 year operating expenses in the amount \$916,264 related to incentive compensation in
6 excess of the "trigger" level. During the 2007 test year, incentive amounts were
7 expensed equal to 125% of the "trigger." This adjustment reduces expense to the
8 "trigger" level amount, which is historically the "normal" level for NIPSCO expenses,
9 and adjusts for true-ups recorded to expense during the test year that were related to the
10 prior year. True-ups occur due to the method by which incentive plan expense is
11 accrued. Incentive plan expense is accrued in the current year based on an estimate of
12 what is expected to be paid out in the following year. Any difference between the
13 amount paid out and the amount accrued is "trued-up" in the payout year, resulting in
14 debits or credits to expense related to the prior year. These adjustments have been offset
15 by the additional incentive compensation for the wage increases outlined in Adjustment
16 OM-5. The adjustment was calculated by comparing the amount currently being accrued
17 for 2008, which anticipates a "trigger" level payout with the amount recorded in 2007.
18 The amount being accrued for 2008, after deducting for the portion capitalized is
19 \$4,957,350. The net amount, after true-ups, and after deducting for the portion
20 capitalized recorded in the 2007 test year was \$6,244,139. The difference between these
21 two amounts is \$1,286,789. A downward adjustment for profit sharing expense of
22 \$38,249 was also computed in the same manner and for the same reasons. The combined

1 total of the two adjustments above was \$1,325,038. After allocating to electric, the net
2 adjustment to electric operating expenses is a reduction (credit) to operating expenses of
3 \$916,264. Mr. Campbell further discusses the Incentive Plan. If this adjustment is not
4 included, test year operating expenses would be overstated.

5 **Q34. Please explain Adjustment OM-7 on Petitioner's Exhibit LEM-2 (Revised).**

6 A34. Adjustment OM-7 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
7 operating expenses in the amount of \$3,925,207 to reflect additional staffing required as a
8 result of workforce aging and retirements. This required additional staffing was not
9 reflected in the test year, and therefore an adjustment is required in order to reflect
10 ongoing levels. This adjustment was calculated by determining the number of
11 replacements that will be needed in each functional area over the next five years,
12 applying the appropriate hourly wage for bargaining unit positions and the appropriate
13 salary for supervisory positions, then applying the cost of benefits. The total of these
14 amounts for the five-year period was averaged, resulting in an annual amount of
15 \$3,925,207. Mr. Campbell discusses the workforce aging program and the number of
16 employees required to provide the necessary services to our customers. If this adjustment
17 is not included, test year operating expenses would be understated.

18 **Q35. Please explain Adjustment OM-8 on Petitioner's Exhibit LEM-2 (Revised).**

19 A35. Adjustment OM-8 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
20 operating expenses in the amount of \$5,016,101 to reflect additional staffing required to
21 fill current vacancies in positions that NIPSCO is actively in the process of securing

1 candidates. This adjustment is being made in order to reflect the proper level of salary
2 expense, since the 2007 test year did not reflect salary expense for these positions that
3 had not yet been filled. This amount was calculated by obtaining a list of 104 vacancies
4 from the Human Resources department and applying the appropriate hourly wage for
5 each bargaining unit position and the appropriate salary amount for each supervisory
6 position. Benefits were then added, as well as incentive compensation based on the
7 incentive range for the position level. The resulting amount was \$9,561,015. Vacancies
8 for electric-specific positions were identified as such and common positions were
9 allocated to electric based on the established common allocation ratios. After
10 determining the electric amount and deducting for the portion capitalized, the net
11 adjustment was an increase (debit) to electric operating expenses of \$5,016,101. Mr.
12 Campbell discusses the number of vacancies and the process NIPSCO utilizes to fill
13 vacant positions. If this adjustment is not included, test year operating expenses would
14 be understated.

15 **Q36. Please explain Adjustment OM-9 on Petitioner's Exhibit LEM-2 (Revised).**

16 A36. Adjustment OM-9 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
17 operating expenses in the amount of \$6,413,789 to reflect additional staffing required to
18 fill 83 new positions necessitated by the organizational structure changes occurring for
19 the Indiana business unit. This adjustment is being made in order to reflect the proper
20 level of salary expense, since the 2007 test year did not reflect salary expense for these
21 positions. NIPSCO currently is in the process of filling these positions. These staffing
22 changes include: senior level positions in Customer Engagement and Communications

intended to increase the Indiana focus; additional management positions in Service Delivery; additional positions needed for new FERC and NERC compliance requirements; a new Resource Planning department; and several additional positions in Generation. The Company also is increasing staffing levels of the Rates department, including positions with responsibility for the DSM programs being developed by the Company to be proposed in a separate filing, and new Regulatory and Legislative Affairs policy management positions, to be located in the Company's Indianapolis office. Estimated salary amounts were applied according to the position level, and benefits and incentive amounts were added in a manner similar to that described in Adjustment OM-8 for staffing vacancies. Positions specific to electric were designated as such, and common positions were allocated to electric using the established common allocation ratios. After determining the electric amount and deducting for the portion capitalized, the net adjustment was an increase (debit) to electric operating expenses of \$6,413,789. NIPSCO Witness Eileen O'Neill Odum describes the Indiana business unit organizational structure and the need for these additional positions. If this adjustment is not included, test year operating expenses would be understated.

Q37. Please explain Adjustment OM-10 on Petitioner's Exhibit LEM-2 (Revised).

A37. Adjustment OM-10 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year operating expenses in the amount of \$448,589 to reflect additional staffing and protective safety equipment required to comply with new regulations and safety initiatives, as these costs were not reflected in 2007 test year expense. The safety program and initiatives and the calculation of this adjustment are discussed by NIPSCO

1 Witness Timothy A. Dehring. If this adjustment is not included, test year operating
2 expenses would be understated.

3 **Q38. Please explain Adjustment OM-11 on Petitioner's Exhibit LEM-2 (Revised).**

4 A38. Adjustment OM-11 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
5 year operating expenses in the amount of \$55,425 to reflect lobbying costs and payment
6 adjustments included in the Edison Electric Institute ("EEI") dues expense during the test
7 year. The Company rejoined the EEI effective the 4th quarter of 2006. In December
8 2006, the Company accrued an estimated amount for 2006 EEI dues because the bill had
9 not yet been received. In January 2007, when the bill was received and paid, the amount
10 due was less than estimated. As a result, a credit to expense of \$72,588 was recorded in
11 2007, which related to the 2006 period. To normalize the test year for EEI dues, an
12 adjustment of \$72,588 was added (debit) to increase operating expenses. A full year of
13 EEI dues was reflected in 2007 expenses, but since the EEI membership dues invoice
14 includes an amount related to lobbying costs, an adjustment has been made to reduce
15 (credit) expenses by \$128,013. The net result of these adjustments related to EEI dues is
16 a decrease (credit) to test year operating expenses of \$55,425. If this adjustment is not
17 included, test year operating expenses would be overstated.

18 **Q39. Please explain Adjustment OM-12 on Petitioner's Exhibit LEM-2 (Revised).**

19 A39. Adjustment OM-12 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
20 year operating expenses in the amount of \$60,063 to remove all institutional and goodwill

1 advertising costs included in account E930.1. If this adjustment is not made, test year
2 operating expenses would be overstated.

3 **Q40. Please explain Adjustment OM-13 on Petitioner's Exhibit LEM-2 (Revised).**

4 A40. Adjustment OM-13 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
5 year operating expenses in the amount of \$200,000 to reflect uncollectible accounts
6 expense. As a result of the Bailly Generating Station N1 refund ordered in this
7 Commission's February 21, 1990 Order in Cause No. 37972, the Company was required
8 to offset this amount against uncollectible accounts expense in the Company's next
9 electric base rate case. If this adjustment is not made, test year operating expenses would
10 be overstated.

11 **Q41. Please explain Adjustment OM-14 on Petitioner's Exhibit LEM-2 (Revised).**

12 A41. Adjustment OM-14 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test
13 year operating expenses in the amount of \$71,796 to reflect increased postal rates
14 effective in May 2007 and May 2008. This adjustment reflects the electric portion of
15 increased postage costs for customer billing. The adjustment was calculated by
16 increasing 2007 test year postage expense in accordance with increased postal rates and
17 then annualizing the increases to reflect ongoing annual amounts. The computation
18 began with 2007 test year actual postage expense of \$3,248,277. I then annualized the
19 postal increase that took effect May 14, 2007. This resulted in a 2007 adjusted amount of
20 \$3,312,597. This amount was then adjusted for the postal increase that took effect May
21 14, 2008, totaling \$3,432,417. The difference between the \$3,432,417 and the 2007

1 actual amount of \$3,248,277 is \$184,140. This amount was then allocated between
2 electric and gas based upon the number of customers, resulting in a net increase (debit) in
3 electric operating expenses of \$71,796. If this adjustment is not included, test year
4 operating expenses would be understated.

5 **Q42. Please explain Adjustment OM-15 on Petitioner's Exhibit LEM-2 (Revised).**

6 A42. Adjustment OM-15 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test
7 year operating expenses in the amount of \$799,403 to reflect increased gasoline and
8 diesel fuel costs. The average cost of bulk gasoline and diesel fuel during the 2007 test
9 year was recalculated utilizing a more current cost (March 2008). The amount of the
10 adjustment was calculated by multiplying the quantity of gasoline and diesel fuel used in
11 the test year times the per gallon rates based on the latest vendor invoices, allocating to
12 electric, and comparing the resulting amount to the total amount spent on gasoline and
13 diesel fuel during the test year. If this adjustment is not included, test year operating
14 expenses would be understated.

15 **Q43. Please explain Adjustment OM-16 on Petitioner's Exhibit LEM-2 (Revised).**

16 A43. Adjustment OM-16 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test
17 year operating expenses in the amount of \$2,078,499 to reflect additional costs for
18 vegetation management. Mr. Dehring discusses this adjustment. If this adjustment is not
19 included, test year operating expenses would be understated.

20 **Q44. Please explain Adjustment OM-17 on Petitioner's Exhibit LEM-2 (Revised).**

1 A44. Adjustment OM-17 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
2 year operating expenses in the amount of \$2,318,771 to reflect items related to services
3 provided by NCS. NIPSCO Witness Susanne M. Taylor discusses the allocation
4 processes and the pro forma adjustment to the 2007 test year. Mr. Hershberger discusses
5 the processes used by NIPSCO accounting to review charges received from NCS and the
6 processes used to identify the adjustment noted above. The \$2,318,771 adjustment is the
7 sum of the adjustments proposed by these two witnesses. If this adjustment is not
8 included, test year operating expenses would be overstated.

9 **Q45. Please explain Adjustment OM-18 on Petitioner's Exhibit LEM-2 (Revised).**

10 A45. Adjustment OM-18 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test
11 year operating expenses in the amount of \$3,187,121 to annualize a change resulting
12 from an improvement in methodology used to allocate common costs between the gas
13 and electric business for NIPSCO. The methodology change took place in the second
14 quarter of the test year. The common allocation methodology and practice historically
15 used was based on a 1968 study. During 2006, a comprehensive review of the
16 methodology was undertaken and changes were made to more accurately reflect the
17 current operations of the Company. In addition, the study was developed to align the cost
18 allocations with the corporate services allocation methodology to provide consistency of
19 allocation methods within NiSource. A complete description of the common allocation
20 study and the methodology is discussed by Mr. Hershberger. The adjustment is made in
21 order to properly reflect a full year of allocated electric costs. The adjustment is
22 computed by applying to the first quarter of the test year the allocation percentages

(similar to those in Mr. Hershberger's Petitioner's Exhibit MEH-4) that would have applied at the time using the new methodology. If this adjustment is not included, test year operating expenses would be understated.

Q46. Please explain Adjustment OM-19 on Petitioner's Exhibit LEM-2 (Revised).

A46. Adjustment OM-19 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$366,293 for non-recoverable advertising costs. To ensure that non-recoverable advertising costs were appropriately excluded, this adjustment was calculated by removing all general advertising costs, per the financial books and records. A review of advertising costs was then undertaken, and those costs related to appropriately recoverable advertising, such as recruitment and safety, were added back in. These types of costs produce a material benefit to the ratepayers. Copies of such advertising are included in the workpapers to be filed in this proceeding. The result was a net reduction (credit) to electric operating expenses of the \$366,293 noted above. If this adjustment is not made, test year operating expenses would be overstated.

Q47. Please explain Adjustment OM-20 on Petitioner's Exhibit LEM-2 (Revised).

A47. Adjustment OM-20 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test year operating expenses in the amount of \$84,528 to remove certain non-recoverable charges, such as lobbying, community sponsorships, and customer and employee relations expenses. The details of this adjustment can be found in the workpapers to be filed in this proceeding. If this adjustment is not included, test year operating expenses would be overstated.

1 **Q48. Please explain Adjustment OM-21 on Petitioner's Exhibit LEM-2 (Revised).**

2 A48. Adjustment OM-21 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test
3 year operating expenses in the amount of \$28,785 to reflect the increased lease costs in
4 NIPSCO's Indianapolis office, as a result of additional new employees and the relocation
5 of an employee from Merrillville. This adjustment was calculated by obtaining the new
6 annual lease amount, deducting for space occupied by the NIPSCO lobbyist because
7 those charges are non-recoverable, and allocating to electric. If this adjustment is not
8 included, test year operating expenses would be understated.

9 **Q49. Please explain Adjustment OM-22 on Petitioner's Exhibit LEM-2 (Revised).**

10 A49. Adjustment OM-22 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test
11 year operating expenses in the amount of \$2,067,189 to reflect increased electric property
12 insurance costs. This adjustment is based on new insurance premiums effective July,
13 2008. The premium increases are a result of increased electric generation property values
14 as used by insurance underwriters for premium determinations. If this adjustment is not
15 included, test year operating expenses would be understated.

16 **Q50. Please explain Adjustments SCOM-23 on Petitioner's Exhibit LEM-2 (Revised).**

17 A50. Adjustment SCOM-23 increases (debits) operating expenses in the amount of \$1,870,352
18 to reflect variable O&M expense required to operate the Sugar Creek Facility. Mr. Pack
19 further describes the calculation of this adjustment.

20 **Q51. Please explain Adjustment SCOM-24 on Petitioner's Exhibit LEM-2 (Revised).**

1 A51. Adjustment SCOM-24 increases (debits) operating expenses in the amount of \$4,048,947
2 for other O&M expenses, which consists of fixed O&M expense for the plant as well as
3 property insurance related to the Sugar Creek Facility. Mr. Pack further describes the
4 calculation of this adjustment.

5 **Q52. Please explain Adjustment OM-25 on Petitioner's Exhibit LEM-2 (Revised).**

6 A52. Adjustment OM-25 decreases (credits) test year operating expenses in the amount of
7 \$5,276,650 to reflect a correction to the 2007 test year medical benefits expense. This
8 correction was made in 2008 subsequent to the filing of the Case-In-Chief. As I indicated
9 previously, during the test year, certain medical benefits costs that the Company paid
10 were coded incorrectly. The result was that they were recorded incorrectly as medical
11 benefits for current employees when in fact they were medical benefits incurred and paid
12 for retired employees. The total amount of the error was \$10,040,730. Of that amount,
13 \$7,630,730 was recorded as expense (i.e., the portion of labor that was expensed). The
14 portion of the reduction in medical benefits expense allocable to electric is \$5,276,650.
15 Mr. Campbell further describes the circumstances of the error.

16 **C. Depreciation and Amortization Adjustments**

17 **Q53. Please explain Adjustment DA-1 on Petitioner's Exhibit LEM-2 (Revised).**

18 A53. Adjustment DA-1 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
19 operating expenses in the amount of \$227,322 to reflect the change in common allocation
20 methodology implemented in the second quarter of the test year. As mentioned above,

1 Mr. Hershberger discusses this change in methodology. If this adjustment is not
2 included, test year operating expenses would be understated.

3 **Q54. Please explain Adjustment DA-2 on Petitioner's Exhibit LEM-2 (Revised).**

4 A54. Adjustment DA-2 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
5 operating expenses in the amount of \$20,820,517 to reflect implementation of new
6 depreciation rates on electric and common property and depreciation/amortization
7 expense associated with Sugar Creek. The annual depreciation/amortization expense for
8 Sugar Creek, included in this adjustment, is \$11,236,857. NIPSCO Witness John J.
9 Spanos has performed a comprehensive depreciation study for electric plant and common
10 plant. The adjustment is based upon his proposed depreciation rates. If this adjustment is
11 not included, test year operating expenses would be understated.

12 **Q55. Please explain Adjustment DA-3 on Petitioner's Exhibit LEM-2 (Revised).**

13 A55. Adjustment DA-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
14 operating expenses in the amount of \$8,256,052 to reflect amortization of the deferral of
15 non-fuel Midwest ISO costs to a regulatory asset beginning August 1, 2006, as approved
16 by this Commission in its June 1, 2005 Order in Cause No. 42685. The amount of total
17 MISO costs deferred to a regulatory asset at December 31, 2007 amounted to
18 \$13,990,057. In addition, MISO non-fuel costs to be deferred through the end of the
19 adjustment period are estimated to be \$10,778,099. The total amount of the deferral is
20 estimated to be \$24,768,156 by year-end 2008. The Company proposes a three-year
21 amortization period. The estimated total of \$24,768,156 amortized over a three-year

1 period is \$8,256,052 annually and therefore requires an increase in electric amortization
2 expense. Because MISO non-fuel costs will continue to be incurred and deferred as
3 described above beyond the end of 2008, and to ensure recovery of all MISO non-fuel
4 costs, the Company proposes that any difference between the estimated and actual
5 amount of the deferral be included as an adjustment via the RA mechanism mentioned
6 previously and described later in my testimony. Mr. Crum provides a detailed discussion
7 of the RA mechanism. If this adjustment is not included, test year operating expenses
8 would be understated.

9 **Q56. Please explain Adjustment DA-4 on Petitioner's Exhibit LEM-2 (Revised).**

10 A56. Adjustment DA-4 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
11 operating expenses in the amount of \$1,979,286 to reflect rate case costs. The Company
12 has estimated a total cost of \$5,937,859 for legal, consulting and expert witness testimony
13 and proposes a three-year amortization period. The total estimated cost over a proposed
14 three-year amortization period is \$1,979,286, and, therefore, requires an increase in
15 electric amortization expense. This estimate will be updated at the time rebuttal
16 testimony is filed to reflect a more accurate amount and the pro forma adjustment will be
17 adjusted at that time. If this adjustment is not included, test year operating expenses
18 would be understated.

19 **Q57. Please explain Adjustment DA-5 on Petitioner's Exhibit LEM-2 (Revised).**

20 A57. Adjustment DA-5 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
21 year operating expenses in the amount of \$935,424 to reflect the completion of the

1 amortization of the Pure Air regulatory asset created as a result of the Commission's
2 October 16, 1991 Order in Cause No. 38849-S1. This asset will be fully amortized by the
3 end of the adjustment period and I have therefore eliminated this expense. If this
4 adjustment is not included, test year operating expenses would be overstated.

5 **Q58. Please explain Adjustment DA-6 on Petitioner's Exhibit LEM-2 (Revised).**

6 A58. Adjustment DA-6 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test year
7 operating expenses in the amount of \$40,657 to reflect the change in common allocation
8 methodology in the second quarter of the test year. Mr. Hershberger further discusses
9 this change and the resulting adjustment. If this adjustment is not included, test year
10 operating expenses would be understated.

11 **Q59. Please explain Adjustment SCDA-7 in Petitioner's Exhibit LEM-2 (Revised).**

12 A59. Adjustment SCDA-7 is the increase (debit) to electric amortization expenses for
13 \$1,459,652 for the amortization of the depreciation/amortization expense of the Sugar
14 Creek Facility proposed to be deferred beginning December 1, 2008 through December
15 31, 2009. The amortization amount is equal to the amount of annual Sugar Creek
16 depreciation/amortization, which is \$11,236,857, reduced by \$4,500,000 (the annual
17 depreciation on the Mitchell plant pursuant to the FAC71 Settlement), divided by twelve
18 to derive a monthly amount of \$561,405 and multiplied by thirteen months to total a
19 deferred amount of \$7,298,262. I have projected the total deferred amount to the
20 anticipated date of an Order in this proceeding. Pursuant to the FAC-71 Settlement, this

1 amount is amortized over a five-year period, resulting in an annual amount of
2 \$1,459,652. .

3 **Q60. Please explain Adjustment SCDA-8 in Petitioner's Exhibit LEM-2 (Revised).**

4 A60. Adjustment SCDA-8 is the increase (debit) to electric amortization expenses for
5 \$4,541,120 for the amortization of the deferred carrying charges on the Sugar Creek
6 Facility. This amount represents the amount of carrying charges proposed to be deferred
7 from December 1, 2008 through December 31, 2009, the anticipated date when rates will
8 become effective. This amount was calculated by multiplying the Sugar Creek rate base
9 gross plant amount of \$322,446,401 (net book value at December 1, 2008) by a rate of
10 6.5% to derive an annual carrying cost of \$20,959,016, divided by twelve for a monthly
11 amount of \$1,746,585 and multiplied by thirteen months to total a deferred amount of
12 \$22,705,601. This amount is amortized over a five-year period, resulting in an annual
13 amount of \$4,541,120.

14 **Q61. Why are you using a 6.5% rate to calculate carrying charges and using a five year**
15 **amortization period?**

16 A61. That rate is consistent with the terms of the FAC71 Settlement as is the five year
17 amortization period.

18 **D. Tax Adjustments**

19 **Q62. Please explain Adjustment OTX-1 on Petitioner's Exhibit LEM-2 (Revised).**

20 A62. Adjustment OTX-1 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
21 year operating expenses in the amount of \$1,045,127 to reflect decreased real estate

1 property taxes as a result of the change in common allocation methodology in the second
2 quarter of the test year. Mr. Hershberger also discusses this change. If this adjustment is
3 not included, test year operating expenses would be overstated.

4 **Q63. Please explain Adjustment OTX-2 on Petitioner's Exhibit LEM-2 (Revised).**

5 A63. Adjustment OTX-2 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
6 year operating expenses in the amount of \$12,431 to reflect decreased federal excise tax
7 as a result of the change in common allocation methodology in the second quarter of the
8 test year. Mr. Hershberger further discusses this change. If this adjustment is not
9 included, test year operating expenses would be overstated.

10 **Q64. Please explain Adjustment OTX-3 on Petitioner's Exhibit LEM-2 (Revised).**

11 A64. Adjustment OTX-3 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test
12 year operating expenses in the amount of \$98,809 to reflect an increase in the Indiana
13 state sales tax percentage from 6% to 7%. This adjustment was calculated by
14 determining the electric Indiana sales tax expense for 2007 and adjusting it for the
15 increase in the state sales tax rate. If this adjustment is not included, test year operating
16 expenses would be understated.

17 **Q65. Please explain Adjustment OTX-4 on Petitioner's Exhibit LEM-2 (Revised).**

18 A65. Adjustment OTX-4 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
19 year operating expenses in the amount of \$18,672 to remove property tax expense for
20 non-utility property. If this adjustment is not included, test year operating expenses
21 would be overstated.

1 **Q66. Please explain Adjustment OTX-5 on Petitioner's Exhibit LEM-2 (Revised).**

2 A66. Adjustment OTX-5 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test
3 year operating expenses in the amount of \$1,257,455 to reflect increased payroll taxes.
4 This adjustment increases payroll taxes for the wage and incentive plan changes
5 discussed in Adjustments OM-5, OM-6, OM-7, OM-8, OM-9, and OM-10. In addition,
6 the adjustment includes an adjustment for payroll taxes related to the increase in taxable
7 base wages for social security tax from \$95,200 to \$102,000. If this adjustment is not
8 included, test year operating expenses would be understated.

9 **Q67. Please explain Adjustment OTX-6 on Petitioner's Exhibit LEM-2 (Revised).**

10 A67. Adjustment OTX-6 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
11 year operating expenses in the amount of \$6,467,208 to reflect Utility Receipts Tax
12 ("URT") as calculated by NIPSCO Witness John M. O'Brien. As I previously discussed,
13 URT associated with fuel and purchased power should not be recovered through base
14 rates in order to be consistent with the Company's request to remove the cost of fuel and
15 purchased power from base rates. In Column F of this same schedule, you will see that I
16 have reclassified URT on fuel and purchased power as an increase (credit) to operating
17 revenue of \$7,177,052 on line 14. In addition, I have reflected an increase (debit) to fuel
18 and purchased power expenses on line 23 as an adjustment of \$7,177,052. These
19 adjustments are made so that the URT on fuel and purchased power will not be recovered
20 through base rates. The adjustments on lines 14 and 23 were calculated by applying the
21 URT rate of 1.40% to the total cost of fuel and purchased power. They are identified as
22 Adjustment OTX-6A in order to differentiate them from Adjustment OTX-6, which is the

1 net effect of an increase (debit) to other tax expense of \$709,844 to reflect the URT on
2 the proposed change in revenue requirement and the decrease (credit) of \$7,177,052 to
3 other tax expense related to fuel and purchased power described above. The detailed
4 calculation can be seen in Petitioner's Exhibit LEM-3.

5 **Q68. Please explain Adjustment OTX-7 on Petitioner's Exhibit LEM-2 (Revised).**

6 A68. Adjustment OTX-7 on Petitioner's Exhibit LEM-2 (Revised) is to increase (debit) test
7 year operating expenses in the amount of \$211,218 to reflect Public Utility Fees related
8 to the increased pro forma revenues at present rates. This amount was calculated by
9 applying the current Public Utility Fees rate to the pro forma revenue adjustments. If this
10 adjustment is not included, test year operating expenses would be understated.

11 **Q69. Please explain Adjustment SCOTX-8 in Petitioner's Exhibit LEM-2 (Revised).**

12 A69. Adjustment SCOTX-8 increases (debits) operating expenses in the amount of \$697,593
13 and is associated with property tax expense on the Sugar Creek Facility. The calculation
14 of this adjustment is described by Mr. O'Brien.

15 **Q70. Please explain Adjustment ITX-1 on Petitioner's Exhibit LEM-2 (Revised).**

16 A70. Adjustment ITX-1 on Petitioner's Exhibit LEM-2 (Revised) is to decrease (credit) test
17 year operating expenses in the amount of \$11,868,829 to reflect lower income taxes.
18 This adjustment is the difference between the test year federal and state income taxes and
19 the Income Taxes Included in Net Operating Income in Petitioner's Exhibit JMO-2
20 sponsored by Mr. O'Brien. This amount includes the interest synchronization calculation

1 Mr. O'Brien performs, plus the other adjustments he describes. If this adjustment is not
2 included, test year operating expenses would be overstated.

3 **IV. PROPOSED REVENUE INCREASE**

4 **Q71. Please explain Adjustment PF-1 on Petitioner's Exhibit LEM-2 (Revised).**

5 A71. Adjustment PF-1 on Petitioner's Exhibit LEM-2 (Revised) shows the calculation of the
6 increased gross margin from base rates in the amount of \$85,744,828, which is calculated
7 to provide the opportunity to earn a return of 8.37% on net original cost rate base of
8 \$2,665,421,829. The increased revenue requirement is calculated by determining the
9 requested increase in operating income. The requested level of operating income is
10 determined by applying the proposed rate of return of 8.37% to the net original cost rate
11 base for NIPSCO (shown on page 3 of Petitioner's Exhibit LEM-2 (Revised)). The
12 requested increase in net operating income is \$50,039,503. The increase in operating
13 income is then grossed up for: (a) Federal income taxes, (b) State income taxes, (c) URT,
14 (d) Public Utility Fees, and (e) uncollectible accounts. The resulting proposed increase in
15 revenue requirement is \$85,744,828.

16 **Q72. Please explain Adjustment PF-2 on Petitioner's Exhibit LEM-2 (Revised).**

17 A72. Adjustment PF-2 on Petitioner's Exhibit LEM-2 (Revised) reflects the additional
18 uncollectible accounts expense on the revenue increase by multiplying the proposed
19 increase in revenue requirement by the multiplier of 0.226593%, for an increase in
20 expense of \$194,292 at the proposed rates level.

21 **Q73. Please explain Adjustment PF-3 on Petitioner's Exhibit LEM-2 (Revised).**

1 A73. Adjustment PF-3 on Petitioner's Exhibit LEM-2 (Revised) is a calculation of the URT
2 applicable to the proposed increase in revenue requirement and is calculated by applying
3 the 1.4% rate to the proposed increase of \$85,744,828, resulting in an increase of
4 \$1,200,428.

5 **Q74. Please explain Adjustment PF-4 on Petitioner's Exhibit LEM-2 (Revised).**

6 A74. Adjustment PF-4 on Petitioner's Exhibit LEM-2 (Revised) is a calculation of the Public
7 Utility Fees applicable to the proposed increase in revenue requirement and is calculated
8 by applying the 0.1204% rate to the proposed increase of \$85,744,828, resulting in an
9 increase of \$103,237.

10 **Q75. Please explain Adjustment PF-5 on Petitioner's Exhibit LEM-2 (Revised).**

11 A75. Adjustment PF-5 on Petitioner's Exhibit LEM-2 (Revised) is to account for income taxes
12 applicable to the proposed increase in net operating income. It is calculated by applying
13 the Federal income tax rate to the pro forma federal taxable income and the Indiana state
14 income tax rate to the pro forma state taxable income, resulting in an increase of
15 \$34,207,368. As Mr.O'Brien explains, federal and state taxable incomes are not the same
16 due to different deductions.

17 **Q76. Please explain Petitioner's Exhibit LEM-3 (Revised).**

18 A76. Petitioner's Exhibit LEM-3 (Revised) consists of a separate page for each income
19 statement adjustment, including those filed in the original Case-In-Chief that are
20 unchanged and the adjustments related to Sugar Creek and the medical benefits
21 correction described earlier in this testimony. The individual pages present additional

1 detail where needed to further explain the amounts included in Petitioner's Exhibit LEM-
2 2 (Revised) and discussed individually in my testimony. Where appropriate, the
3 workpapers to be filed in this proceeding provide further detail.

4 **V. NET ORIGINAL COST RATE BASE**

5 **Q77. Please explain Petitioner's Exhibit LEM-4 (Revised).**

6 A77. Petitioner's Exhibit LEM-4 (Revised), page 1 of 2, quantifies NIPSCO's net original cost
7 rate base as of December 31, 2007, including updates, which I describe later in my
8 testimony. Column B shows the actual rate base as of December 31, 2007, per
9 NIPSCO's books. Column C shows the debit and credit updates to rate base by line item.
10 Column D shows the total net original cost rate base with the rate base updates reflected.
11 Petitioner's Exhibit LEM-4 (Revised), page 2 of 2, shows the detail of the rate base
12 updates, which is further discussed below.

13 **Q78. Please explain Update RB-1 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2.**

14 A78. Update RB-1 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2, decreases (credits)
15 utility plant in service in the amount of \$175,909,015 to reflect the removal of units at
16 Mitchell, which are being retired. Ms. Odum and Mr. Sweet further discuss the
17 Company's plans regarding Mitchell.

18 **Q79. Please explain Update RB-2 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2.**

19 A79. Update RB-2 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2, decreases (debits)
20 accumulated depreciation reserve in the amount of \$178,072,088 to reflect the retirement
21 of Mitchell.

1 **Q80. Please explain Update RB-3 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2.**

2 A80. Update RB-3 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2, decreases (credits)
3 utility plant in service in the amount of \$19,395,755 to reflect removal of the Michigan
4 City Generating Station Units 2 and 3, which are being retired. Ms. Odum and Mr. Sweet
5 further discuss the Company's plans regarding Units 2 and 3 at the Michigan City
6 Generating Station.

7 **Q81. Please explain Update RB-4 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2.**

8 A81. Update RB-4 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2, decreases (debits)
9 accumulated depreciation reserve in the amount of \$18,096,416 to reflect the retirement
10 of the Michigan City Generating Station Units 2 and 3.

11 **Q82. Please explain Updates RB-5 through RB-10 on Petitioner's Exhibit LEM-4**
12 **(Revised), page 2 of 2.**

13 A82. As discussed in greater detail by Mr. Dehring and NIPSCO Witness Robert Greneman,
14 the Company implemented the FERC Seven Factor Test relating to the electric
15 transmission and distribution facilities as set forth in FERC Order No. 888. This resulted
16 in \$108,644,289 of transmission assets being re-classified as distribution assets and
17 \$14,599,077 of distribution assets being re-classified as transmission assets. This update
18 has no impact on total plant in service values. In addition, the accumulated depreciation
19 and amortization reserves were adjusted. These updates are identified as RB-5 and RB-6.
20 In addition, the Company made updates to rate base to reflect the impact of an error made
21 in performing certain plant retirements and made other adjusting entries to correct assets

1 that had been misclassified as to specific plant account. These updates are identified as
2 RB-7 through RB-10. Mr. Hershberger further discusses these adjustments.

3 **Q83. Please explain Update RB-11 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2.**

4 A83. Update RB-11 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2, increases (debits)
5 rate base in the amount of \$1,495,291 to reflect Materials and Supplies for the Sugar
6 Creek Facility.

7 **Q84. Please explain Updates RB-12 and RB-13 on Petitioner's Exhibit LEM-4 (Revised),**
8 **page 2 of 2.**

9 A84. Updates RB-12 and RB-13 on Petitioner's Exhibit LEM-4 (Revised), page 2 of 2, reflect,
10 respectively, the increase (debit) to rate base in the amount of \$328,064,833 to reflect
11 gross utility plant for the Sugar Creek Facility and the increase (credit) to accumulated
12 depreciation for the Sugar Creek Facility for the period June 1, 2008 through November
13 30, 2008.

14 **Q85. Please discuss the Deferred Charges shown on Petitioner's Exhibit LEM-4**
15 **(Revised), page 1 of 2.**

16 A85. The deferred charges shown on Petitioner's Exhibit LEM-4 (Revised), page 1 of 2, relate
17 to the unamortized balance at December 31, 2007 of deferred charges in connection with
18 the (1) Pure Air flue gas desulfurization ("FGD") at the Bailly Generating Station, (2) R.
19 M. Schahfer Generating Station Units 17 and 18, and (3) prepaid pension asset.

20 **Q86. Please explain the Pure Air Deferred Charges on Petitioner's Exhibit LEM-4**
21 **(Revised), page 1 of 2.**

1 A86. The Pure Air Deferred Charges on Petitioner's Exhibit LEM-4 (Revised), page 1 of 2, in
2 the amount of \$526,218 represent the remaining unamortized balance of the regulatory
3 asset established in Cause No. 43188. This asset will be fully amortized by year-end
4 2008.

5 **Q87. Please explain the Unit 17 Depreciation on Petitioner's Exhibit LEM-4 (Revised),**
6 **page 1 of 2.**

7 A87. The Unit 17 Depreciation on Petitioner's Exhibit LEM-4 (Revised), page 1 of 2, in the
8 amount of \$542,928 relates to the deferral of depreciation on Schahfer Unit 17 after it
9 went into service and before entry of the Commission's August 3, 1983 Order in Cause
10 No. 37023 (including Unit 17 in NIPSCO's rate base). Pursuant to the Commission's
11 April 20, 1983 Order in Cause No 37129, the Company was authorized to defer and
12 amortize the deferred depreciation over the remaining life of Schahfer Unit 17. The
13 amount of \$542,928 is the unamortized amount of deferred charges at December 31,
14 2007.

15 **Q88. Have you removed from rate base the unamortized amount of the Schahfer Unit 17**
16 **disallowance ordered by the Commission?**

17 A88. Yes, I removed the unamortized amount of the disallowance of \$4,334,003, which
18 consists of gross plant of \$31,733,655 and accumulated amortization of \$27,399,652 as
19 shown on Petitioner's Exhibit LEM-4 (Revised).

20 **Q89. Please explain the Unit 18 Depreciation and Carrying Charges on Petitioner's**
21 **Exhibit LEM-4 (Revised), page 1 of 2.**

1 A89. The Unit 18 Depreciation and Carrying Charges on Petitioner's Exhibit LEM-4
2 (Revised), page 1 of 2, in the amounts of \$5,206,694 and \$16,132,193, respectively,
3 relate to the continuation of Allowance for Funds Used During Construction ("AFUDC")
4 and the deferral of depreciation from the time Schahfer Unit 18 went into service until the
5 time it was included in rate base. In the Commission's July 15, 1987 Order in Cause No.
6 38045, the Company was authorized to phase-in this unit into rate base. In the
7 Commission's November 27, 1985 Order in Cause No. 37819, the Company was
8 authorized to amortize these deferrals over the remaining life of Schahfer Unit 18. The
9 amount of \$21,338,887 reflects the unamortized amount of Schahfer Unit 18 deferred
10 charges at December 31, 2007.

11 **Q90. Please explain the Prepaid Pension Asset on Petitioner's Exhibit LEM-4 (Revised)**
12 **page 1 of 2.**

13 A90. The Prepaid Pension Asset on Petitioner's Exhibit LEM-4 (Revised), page 1 of 2, reflects
14 the electric portion of prepaid pension costs in the amount of \$25,705,004.

15 **Q91. Please explain the Materials & Supplies on Petitioner's Exhibit LEM-4 (Revised),**
16 **page 1 of 2?**

17 A91. The Materials & Supplies on Petitioner's Exhibit LEM-4 (Revised), page 1 of 2, reflects
18 the balance of the electric materials and supplies at December 31, 2007 per the
19 Company's books and records in the amount of \$46,907,735, updated for Sugar Creek
20 materials and supplies in the amount of \$1,495,291, which reflects the working capital
21 adjustment related to the acquisition of the Sugar Creek Facility.

1 **Q92. Please explain the Production Fuel on Petitioner's Exhibit LEM-4 (Revised), page 1**
2 **of 2?**

3 A92. The Production Fuel on Petitioner's Exhibit LEM-4 (Revised), page 1 of 2, reflects the
4 balance of production fuel at December 31, 2007 per the Company's books and records
5 in the amount of \$57,566,559.

6 **VI. CAPITAL STRUCTURE**

7 **Q93. Please explain Petitioner's Exhibit LEM-5 (Revised).**

8 A93. Petitioner's Exhibit LEM-5 (Revised), page 1 of 3, shows the computation of the overall
9 weighted cost of capital for NIPSCO. Column A shows the components of capital,
10 including common equity, long term debt, customer deposits, deferred income taxes,
11 postretirement liability, and Post 1970 ITC. Column B shows the "as adjusted" amount
12 for each component. Column C shows the percent each component represents of the total
13 capitalization. Column D shows the cost for each component. Column E shows the
14 weighted average cost for each component. The cost of Post-1970 ITC represents the
15 weighted average cost of investor supplied capital, which is computed in the second table
16 on Page 1 of 3 on Petitioner's Exhibit LEM-5 (Revised). The total of Column E of
17 8.37% is the Company's weighted cost of capital. Petitioner's Exhibit LEM-5 (Revised),
18 page 2 of 3, shows the December 31, 2007 actual capital structure and the adjustments
19 made to arrive at the capital structure reflected on page 1. Column B shows the actual
20 December 31, 2007 balances. Columns C and D show the updates to capital structure.
21 Column E shows the reference to these updates, the detail of which is discussed below.
22 Column F shows the adjusted balance. Column G reflects the percent of the total

capitalization for each component. Column H shows the cost for each component. Column I shows the weighted average cost for each component. Petitioner's Exhibit LEM-5 (Revised), Page 3 of 3, is a detailed schedule of long-term debt, reflecting actual debt outstanding at December 31, 2007 as well as debt issued in June 2008. Column A reflects the interest rate associated with each debt issue. The individual debt issues are listed in Column B. Columns C and D reflect the dates of issuance and dates of maturity, respectively. The principal amount outstanding is shown in Column E. Column F reflects the interest requirement, which is the principal amount (Column E) multiplied by the interest rate (Column A). Column G reflects the overall cost of debt, which flows to page 1 of 3.

Q94. What cost rate has been utilized for Common Equity on Petitioner's Exhibit LEM-5 (Revised)?

A94. The cost rate for Common Equity on Petitioner's Exhibit LEM-5 (Revised), page 1 of 3, is 12%. The cost rate was determined and provided by NIPSCO Witness Paul R. Moul.

Q95. What cost rate has been utilized for Long-Term Debt on Petitioner's Exhibit LEM-5 (Revised)?

A95. The cost rate for Long-Term Debt on Petitioner's Exhibit LEM-5 (Revised), page 1 of 3, is 6.56%, which is based on the debt outstanding at December 31, 2007 plus debt issued in June 2008. The update for the June 2008 debt issue is shown on Petitioner's Exhibit LEM-5 (Revised), page 2 of 3, and is discussed below.

1 **Q96. What cost rate has been utilized for Customer Deposits as shown on Petitioner's**
2 **Exhibit LEM-5 (Revised)?**

3 A96. The cost rate for Customer Deposits on Petitioner's Exhibit LEM-5 (Revised), page 1 of
4 3, is 6%, which is the interest rate on customer deposits as provided for in the
5 Commission's rules.

6 **Q97. Please explain Post-Retirement Liability on Petitioner's Exhibit LEM-5 (Revised)?**

7 A97. The Post-Retirement Liability on Petitioner's Exhibit LEM-5 (Revised) reflects the
8 Statement of Financial Accounting Standard No. 106 ("SFAS 106") OPEB accrual
9 expense in excess of the cash basis or Pay-As-You-Go Method ("PAYGO"). In
10 accordance with the Commission's June 11, 1997 Order in Cause No. 40688, the
11 Commission found that, commencing February 1, 1998, NIPSCO was authorized to
12 include its SFAS 106 expense in its cost of service for ratemaking purposes.
13 Additionally, the Commission authorized NIPSCO to commence the amortization of the
14 expense that had been deferred as a regulatory asset pursuant to the Commission's
15 December 30, 1992 Order in Cause No. 39348. The Commission also found that the
16 cumulative difference between SFAS 106 expense and the cash outlay for post-retirement
17 benefits other than pensions should be treated as zero cost capital. I have computed this
18 adjustment by starting with the SFAS 106 gross accrual amounts (which includes all of
19 the expenses deferred in the regulatory asset prior to February 1, 1997), then reducing for
20 amounts paid as calculated under the PAYGO, then reducing further by the unamortized
21 balance of the regulatory asset, then finally reducing by the capitalized portion. In this
22 fashion, the amount reflected as zero cost capital is essentially equivalent to the amount

1 that would have been recorded as SFAS 106 expense in excess of the PAYGO since
2 February 1, 1997, together with the amount of the original regulatory asset that has been
3 amortized, all as provided for in the Commission's Order in Cause No. 40688.

4 **Q98. What updates were made to the capital structure?**

5 A98. Adjustments CS-1, CS-2, CS-3 and CS-4 were made with respect to common equity,
6 long-term debt, deferred taxes and retirement liability, respectively. These adjustments
7 are shown on Petitioner's Exhibit LEM-5 (Revised), page 2 of 3, and are discussed
8 below.

9 **Q99. Please explain Adjustment CS-1 on Petitioner's Exhibit LEM-5 (Revised).**

10 A99. Adjustment CS-1 on Petitioner's Exhibit LEM-5 (Revised) is an increase (credit) in
11 common equity in the amount of \$1,168,208, made to reflect the exclusion of Other
12 Comprehensive Income ("OCI") from the December 31, 2007 balance. This adjustment
13 to common equity is necessary as the OCI is related to the market impact of derivative
14 activity which is non cash in nature. Mr. Moul provides further discussion of this item.

15 **Q100. Please explain Adjustment CS-2 on Petitioner's Exhibit LEM-5 (Revised).**

16 A100. Adjustment CS-2 on Petitioner's Exhibit LEM-5 (Revised) is an increase (credit) in long-
17 term debt in the amount of \$160,000,000, made to reflect the long-term debt issued by
18 NIPSCO to NiSource Finance Corporation in June 2008. This debt was issued as a
19 replacement for the 2007 redemption of NIPSCO's preferred stock as well as scheduled
20 maturities of medium-term notes. The Commission approved the issuance of these notes
21 in its February 6, 2008 Order in Cause No. 43370. This issue consisted of two

1 components, and the capital structure reflects the interest rate applicable to each portion
2 of the debt issue, totaling \$160,000,000. NIPSCO Witness Vincent V. Rea discusses the
3 financing and interest rate determination.

4 **Q101. Please explain Adjustment CS-3 on Petitioner's Exhibit LEM-5 (Revised).**

5 A101. Adjustment CS-3 on Petitioner's Exhibit LEM-5 (Revised) is an increase (credit) to the
6 capital structure in the amount of \$795,992 in order to exclude the deferred taxes related
7 to the OCI adjustment to common equity for the derivative activity discussed previously.

8 **Q102. Please explain Adjustment CS-4 on Petitioner's Exhibit LEM-5 (Revised).**

9 A102. Adjustment CS-4 on Petitioner's Exhibit LEM-5 (Revised) corrects the zero cost capital
10 component for SFAS 106 to account for the error in medical benefits expense
11 (Adjustment OM-25) I described previously. These are amounts the Company incurred
12 for medical benefits costs that should have been reflected as reductions in the SFAS 106
13 accrued liability rather than active employee medical benefits costs. When computing
14 the amount for SFAS 106 accruals to include in the capital structure at zero cost, the
15 amounts actually paid for such benefits (the PAYGO amounts must be subtracted). The
16 correction for this error increases the amount that was actually paid for retiree benefits
17 and thereby reduces the Retirement Liability component of the capital structure by the
18 same amount. As indicated previously, the total amount of the error was \$10,040,730,
19 and so that is the amount by which zero cost capital is also reduced. Petitioner's Exhibit
20 LEM-5 (Revised), pages 1 and 2 of 3 have been revised to reflect a Total Company
21 Capitalization amount of \$2,793,695,583 and Weighted Average Cost of 8.37%.

VII. TRACKER MECHANISMS

Q103. Is NIPSCO proposing any tracking mechanisms in this proceeding?

A103. Yes, NIPSCO is proposing the continuation of its FAC, EERM, and Environmental Cost Recovery Mechanism ("ECRM") tracking mechanisms. As part of this rate case proceeding, NIPSCO seeks approval for a change in the frequency of the filing of its EERM to semi-annual from annual and for approval for use of the EERM to pass back to ratepayers the net proceeds realized through the sale of emissions allowances, as well as any costs incurred to purchase allowances. In addition to the continuation of these existing tracking mechanisms with the requested modifications, NIPSCO is proposing the RA tracking mechanism to provide for (1) recovery and pass-through of certain regional transmission organization costs and revenues; (2) recovery of purchased power costs; and (3) the allocation of net revenues from NIPSCO's off-system sales. As described previously in REV-8 and FP-5, NIPSCO proposes that 100% of future off-system sales margins be passed back to the ratepayers up to \$15 million annually. NIPSCO requests that any off-system sales margins generated beyond the amount of \$15 million annually will be shared, with 80% going to ratepayers. In addition, as noted in Adjustment REV-10, the Company proposes that 100% of transmission revenues from certain MISO schedules be passed back to ratepayers via this RA mechanism. Mr. Crum further describes this mechanism. I describe the schedules that will be utilized for the proposed RA tracking mechanism below.

Q104. Please describe Petitioner's Exhibit LEM-10.

1 A104. Petitioner's Exhibit LEM-10 shows the sample schedules proposed to be utilized with the
2 proposed RA tracking mechanism. NIPSCO proposes that this mechanism be filed
3 quarterly concurrent with the quarterly FAC filings. The RA is intended to be utilized to
4 recover purchased power and capacity costs, all non-FAC MISO charges / (credits) and to
5 pass through off-system sales net revenues. Petitioner's Exhibit LEM-10 contains sample
6 schedules with hypothetical dollar amounts and allocation percentages for hypothetical
7 dates in order to demonstrate how Petitioner proposes this mechanism will function.
8 Petitioner proposes that a quarterly estimate be prepared in order to bill customers and
9 that a reconciliation of costs recovered to actual costs incurred be performed in a
10 subsequent quarter, much like the process used for the existing FAC mechanism.
11 Petitioner's Exhibit LEM-10, page 1 of 9, is the summary page showing the estimated
12 costs / (credits) to be included in the RA and the resulting factors to be billed to
13 customers. Lines 1 and 2 show capacity purchases and MISO charges that are demand
14 allocated, respectively. Both of these line items will be allocated to NIPSCO's proposed
15 rate schedules based on demand factors. Line 3 is the total of Lines 1 and 2. Lines 4, 5
16 and 6 show energy purchases, all other non-FAC MISO charges / (credits) and off-system
17 sales net revenues, respectively. Each of these three line items will be allocated to
18 NIPSCO's proposed rate schedules based on energy. Line 7 is the sum of the Lines 4, 5
19 and 6. Lines 8 through 23 show the allocation of demand allocated and energy allocated
20 charges by rate. Lines 24 through 39 show the total combined charges plus the variance
21 from previous periods. Line 39, column L shows the total net charges / (credits) to be
22 billed to customers by rate schedule and column M reflects the factor for each rate

1 schedule. Column N is the billing factor adjusted for URT and Adjusted Gross Income
2 Tax. Petitioner's Exhibit LEM-10, pages 2 through 5 of 9, reflect the detail behind Page
3 1 of 9, Lines 1, 2, 4, 5, and 6, as described above. Petitioner's Exhibit LEM-10, page 6
4 of 9, shows the charges recovered for the quarter less the amount of prior period variance
5 to be recovered, compared to actual charges for the quarter, and the new resulting
6 variance. Petitioner's Exhibit LEM-10, page 7 of 9, shows the detailed reconciliation and
7 allocation of actual costs based on demand and energy as explained above. Petitioner's
8 Exhibit LEM-10, page 8 of 9, shows actual costs / (credits) by type. Petitioner's Exhibit
9 LEM-10, page 9 of 9, shows a detailed list of MISO charge-types. For simplicity
10 purposes, this reconciliation is shown for one of the three months in the quarter. The
11 remaining two months would be shown on similar pages.

12 **Q105. Please describe how the EERM and ECRM tracking mechanisms will be impacted**
13 **upon the issuance of an Order in this proceeding.**

14 A105. Prior to the issuance of an Order in this proceeding, the ECRM and EERM tracker filings
15 will be separated to delineate those costs and expenses that have been included in the
16 requested revenue requirement in this proceeding from expenditures and operating
17 expenses not reflected in the revenue requirement for this proceeding. Upon the issuance
18 of an Order in this proceeding, new tariff tracker schedules will be utilized to remove the
19 impact of the costs and expenses reflected in new rates to ensure that there is no
20 duplication in revenue collection. These tracking mechanisms will continue to be utilized
21 for future Qualified Pollution Control Property ("QPCP") not reflected in rate base and
22 for future operating costs associated with QPCP expenditures, in accordance with the

1 Commission's prior orders in Cause Nos. 42150 (11/26/2002) and 43188 (7/3/2007). In
2 addition, Petitioner is requesting in this proceeding that these mechanisms be expanded to
3 make them applicable for costs associated with additional and future environmental
4 regulatory requirements and also requests that both tracker filings may be made **on a**
5 **semi-annual basis.**

6 **Q106. Does this conclude your prepared direct testimony?**

7 A106. Yes, it does.

VERIFICATION

I, Linda E. Miller, Executive Director, Rates and Regulatory Finance for NiSource Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.


Linda E. Miller

Date: December 19, 2008

Northern Indiana Public Service Company
Statement of Operating Income
Actual, Pro Forma and Proposed
For the Twelve Month Period Ending December 31, 2007

Line No.	Description	Actual	Pro Forma Adjustments Increases (Decreases)	Ref.	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref.	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
1	Operating Revenue							
2	Revenue	\$ 1,359,522,750			\$ 1,400,964,753	85,744,828	PF-1	\$ 1,486,709,581 *
3	Abnormal Weather		(14,604,146)	REV - 1				
4	EDR Revenue Imputation		1,432,424	REV - 2				
5	Special Contract Revenue Imputation		80,082,674	REV - 3				
6	FAC 71 Settlement		33,500,000	REV - 4				
7	Non-recurring Revenue Financial transactions		(2,203,737)	REV - 5				
8	Major Industrial Contract Changes (Metal Melters)		(804,136)	REV - 6				
9	Unbilled		10,855,615	REV - 7				
10	Off-System Sales		(50,400,058)	REV - 8				
11	2007 Emission Allowance Revenue		(11,790,599)	REV - 9				
12	2007 Transmission Revenue		(4,726,034)	REV - 10				
13	Add							
14	Utility Receipts Tax (related to fuel and purchased power)					7,177,052	OTX-6A	7,177,052
15	Total Operating Revenue	\$ 1,359,522,750	\$ 41,442,003		\$ 1,400,964,753	\$ 92,921,880		\$ 1,493,886,633
16	Fuel and Purchased Power	\$ 548,972,918			\$ 524,316,389			\$ 524,316,389
17	Fuel Related to Operating Revenue Adjustments		(3,683,450)	FP - 1				
18	Fuel Related to Operating Revenue (Metal Melters)		(628,813)	FP - 2				
19	Mobile Fuel Handling Expense		100,891	FP - 3				
20	Gas and Diesel		840,335	FP - 4				
21	Off-System Sales		(21,285,492)	FP - 5				
22	Add							
23	Utility Receipts Tax (related to fuel and purchased power)					7,177,052	OTX-6A	7,177,052
24	Total Fuel and Purchased Power	\$ 548,972,918	\$ (24,856,529)		\$ 524,316,389	\$ 7,177,052		\$ 531,493,441
25	Gross Margin	\$ 810,549,832	\$ 66,098,532		\$ 876,648,364	\$ 85,744,828		\$ 962,393,192
26	Operations and Maintenance Expenses	\$ 299,413,573			\$ 341,707,536			\$ 341,707,536
27	Production Expenses (Contractors)		1,006,664	OM - 1				
28	Variable Production Expenses		4,001,238	OM - 2				
29	Pension		5,762,558	OM - 3				
30	FAS No. 106 Other Post Retirement Benefits		5,762,480	OM - 4				
31	Wage Increases		5,083,259	OM - 5				
32	Incentive Compensation		(916,264)	OM - 6				
33	Workforce Aging		3,925,207	OM - 7				
34	Staffing Vacancies		5,016,101	OM - 8				
35	Staffing Additions		6,413,789	OM - 9				
36	Safety Program		448,589	OM - 10				
37	EET Lobbying Expenses		(55,425)	OM - 11				
38	Goodwill Advertising		(60,063)	OM - 12				
39	Uncollectible Accounts		(200,000)	OM - 13				
40	U.S. Postage Increase		71,798	OM - 14				
41	Gas & Diesel		799,403	OM - 15				
42	Tree Trimming Expense		2,078,499	OM - 16				
43	NISource Corporate Allocations (NCSF)		(2,316,771)	OM - 17				
44	NIPSCO Common Allocations		3,167,121	OM - 18				
45	Advertising		(386,293)	OM - 19				
46	Selected Payments		(84,528)	OM - 20				
47	Indy Office Rent		28,785	OM - 21				
48	Property Insurance		2,067,189	OM - 22				
49	Sugar Creek Variable Cost		1,870,352	SCOM - 23				
50	Sugar Creek Operating and Maintenance Cost		4,048,947	SCOM - 24				
51	Medical benefit cost		(6,276,650)	OM - 25				
52	Total Operations and Maintenance	\$ 299,413,573	\$ 42,293,963		\$ 341,707,536	\$ 194,282		\$ 341,901,828
53	Depreciation Expense	\$ 176,244,660			\$ 197,292,499	\$ -		\$ 197,292,499
54	Depreciation Expense (Common Allocation)		227,322	DA - 1				
55	Depreciation Expense - New Rates and Sugar Creek		20,820,517	DA - 2				
56	Total Depreciation Expense	\$ 176,244,660	\$ 21,047,839		\$ 197,292,499	\$ -		\$ 197,292,499

* Operating Revenue at Proposed Rates (Line 2, Column H) excludes Utility Receipts Tax on fuel and purchased power.

Line No.	Description A	Actual B	Pro Forma Adjustments Increases (Decreases) C	Ref. D	Pro Forma Results Based on Current Rates E	Pro Forma Adjustments Increases (Decreases) F	Ref. G	Pro Forma Results Based on Proposed Rates H
57	<u>Amortization Expense</u>	\$ 15,673,481			\$ 31,014,824	\$ -		\$ 31,014,824
58	Amortization Expense (Reg Assets) - MISO		8,258,052	DA - 3				
59	Amortization Expense (Reg Assets) - Rate Case		1,979,286	DA - 4				
60	Amortization Expense (Reg Assets) - Pure Air		(935,424)	DA - 5				
61	Amortization Expense - Computer Software		40,657	DA - 6				
62	Sugar Creek - Deferred Depreciation		1,459,852	SCDA - 7				
63	Sugar Creek - Deferred Carrying Charges		4,541,120	SCDA - 8				
64	Total Amortization Expense	\$ 15,673,481	\$ 15,341,343		\$ 31,014,824	\$ -		\$ 31,014,824
65	<u>Taxes</u>							
66	<u>Taxes Other than Income</u>	\$ 60,625,916			\$ 55,347,553			\$ 55,347,553
67	Real Estate/Personal Property Tax - Common Allocation		(1,045,127)	OTX - 1				
68	Federal Excise Tax - Common Allocation		(12,431)	OTX - 2				
69	State Sales Tax- Increase from 6% to 7%		98,809	OTX - 3				
70	Property Tax Expense - NonUtility		(18,672)	OTX - 4				
71	Payroll Tax		1,257,455	OTX - 5				
72	Indiana Utility Receipts Tax		(6,467,208)	OTX - 6		1,200,428	PF - 3	1,200,428
73	Public Utility Fee		211,216	OTX - 7		103,237	PF - 4	103,237
74	Sugar Creek Property Tax		697,593	SCOTX - 8				
75	Total Taxes Other Than Income	\$ 60,625,916	\$ (5,278,363)		\$ 55,347,553	\$ 1,303,664		\$ 56,651,217
76	<u>Income Taxes</u>							
77	Federal and State Taxes	\$ 90,098,476	\$ (11,868,829)	ITX - 1	\$ 78,229,647	\$ 34,207,368	PF - 5	\$ 112,437,015
78	Total Taxes	\$ 150,724,392	\$ (17,147,192)		\$ 133,577,200	\$ 35,511,033		\$ 169,088,233
79	Total Operating Expenses	\$ 642,056,106	\$ 61,535,953		\$ 703,592,059	\$ 35,705,325		\$ 739,297,384
80	Required Net Operating Income	\$ 168,493,726	\$ 4,562,579		\$ 173,056,305	\$ 50,039,503		\$ 223,095,808

* Operating Revenue at Proposed Rates (Line 2, Column H) excludes Utility Receipts Tax on fuel and purchased power.

Northern Indiana Public Service Company
Calculation of Proposed Revenue Increase
Based on Pro Forma Operating Results
Original Cost Rate Base Estimated at December 31, 2007

Line No.	Description	Revenue Deficiency
1	Net Original Cost Rate Base	\$ 2,665,421,829
2	Rate of Return	8.37%
3	Required Net Operating Income	223,095,808
4	Pro Forma Net Operating Income	173,056,305
5	Increase in Net Operating Income (NOI Shortfall)	50,039,503
6	Effective Incremental Revenue/NOI Conversion Factor	58.36%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)	\$ 85,744,828
8	One	1.000000
9	Less: Public Utility Fee	0.001204
10	Less: Bad Debt	0.002266
11	One Less PUF, IURT, Bad Debt	0.996530
12	One	1.000000
13	Less: Public Utility Fee	0.014000
14	Taxable Adjusted Gross Income Tax	0.996530
15	Adjusted Gross Income Tax Rate	0.085000
16	Adjusted Gross Income Tax	0.084705
17	Indiana Apportionment	0.996530
18	Indiana State Income Tax Rate	0.085000
19	Effective Indiana Income Tax Rate	0.084705
20	Line 11 less line 13 less line 19	0.897825
21	One	1.000000
22	Less: Federal Income Tax Rate	0.350000
23	One Less Federal Income Tax Rate	0.650000
24	Effective Incremental Revenue / NOI Conversion Factor	58.36%

Northern Indiana Public Service Company
Requested Revenue Increase Reconciliation
For the Twelve Month Period Ended December 31, 2007

Line No.	Description	Margin at Present Rates	Adjustment to Base Rates	Margin at Proposed Rates
	A	B	C	D
1	Base Revenue (less cost of fuel)	\$ 836,907,692	\$ 85,744,828	\$ 922,652,520
2	Add: ECRM	\$ -	\$ 25,627,423	\$ 25,627,423
3	Add: EERM	\$ -	\$ 14,113,249	\$ 14,113,249
4	Adjusted Base Revenue (less cost of fuel)	\$ 836,907,692	\$ 125,485,500	\$ 962,393,192
5	<u>Riders / Trackers:</u>			
6	ECRM	\$ 25,627,423	\$ (25,627,423)	\$ -
7	EERM	\$ 14,113,249	\$ (14,113,249)	\$ -
8	<u>Proposed:</u>			
9	Total Riders/Trackers	\$ 39,740,672	\$ 39,740,672	\$ -
10	Total Margin	\$ 876,648,364	\$ 85,744,828	\$ 962,393,192
11	Net Increase/(Decrease) in Base Rate Revenue		\$ 85,744,828	
12	Total Margin	\$ 876,648,364	\$ 85,744,828	\$ 962,393,192
13	Net Customer Bill Impacts, Net Increase (Decrease)		\$ 85,744,828	

Northern Indiana Public Service Company
Sugar Creek
Pro Forma Adjustment to Operation and Maintenance Expense
Twelve Months Ended December 31, 2007

This pro forma adjustment increased 2007 test year O&M expense to adjust for Sugar Creek variable operating costs.

Line No.	Description A	Amount B
1	Maintenance Parts & Service	\$ 447,069
2	Long-Term Service Agreement	\$ 1,274,300
3	Chemicals	\$ 148,983
4	Increase in Pro Forma Test Year O&M Expense	\$ 1,870,352

Northern Indiana Public Service Company
Sugar Creek
Pro Forma Adjustment to Operation and Maintenance Expense
Twelve Months Ended December 31, 2007

This pro forma adjustment increased 2007 test year O&M expense to adjust for other Sugar Creek operating and maintenance costs.

Line No.	Description	Amount
	A	B
1	Increase in Pro Forma Test Year O&M Expense	<u>\$ 4,048,947</u>

Northern Indiana Public Service Company

Pro Forma Adjustment to Operation and Maintenance Expense
Twelve Months Ended December 31, 2007

This pro forma adjustment decreased 2007 test year O&M expense to adjust for correction of active medical benefit costs.

Line No.	Description	Amount
	A	B
1	Decrease in Pro Forma Test Year O&M Expense	<u>\$ (5,276,650)</u>

Northern Indiana Public Service Company
Pro Forma Adjustment to Depreciation and Amortization Expense
Twelve Months Ended December 31, 2007

This pro forma adjustment increased 2007 test year depreciation and amortization expense to reflect the expense amount calculated using new depreciation rates per the depreciation study.

Line No.	Description A	Amount B
1	2007 Actual Depreciation Expense	\$ 176,244,660
2	D&A Study Depreciation Expense	\$ 185,828,320
3	Sugar Creek Depreciation Expense	\$ 11,236,857
4	Total Depreciation - New Rates and Sugar Creek	<u>\$ 197,065,177</u>
5	Increase in Pro Forma Test Year Depreciation and Amortization Expense	<u>\$ 20,820,517</u>

Sugar Creek
Pro Forma Adjustment to Depreciation and Amortization Expense
Twelve Months Ended December 31, 2007

This pro forma adjustment increased 2007 test year depreciation and amortization expense to amortize costs of deferred depreciation on Sugar Creek per Cause No. 43396.

Line No.	Description	Amount
	A	B
1	Annual Depreciation	\$ 11,236,857
2	Annual Reduction (FAC71-S1)	\$ 4,500,000
3	Annual Depreciation Deferred	\$ 6,736,857
4	Months (December 1, 2008 through December 31, 2009)	<u>13</u>
5	Total Depreciation Deferred (Line 3 divided by 12, multiplied by 13)	\$ 7,298,262
6	Amortization Period in Years Per Cause No. 43396	<u>5</u>
7	Increase in Pro Forma Test Year Depreciation and Amortization Expense	<u>\$ 1,459,652</u>

Northern Indiana Public Service Company
Sugar Creek
Pro Forma Adjustment to Depreciation Expense
Twelve Months Ended December 31, 2007

This pro forma adjustment increased 2007 test year depreciation and amortization expense to amortize the costs of deferred carrying charges on Sugar Creek per Cause No. 43396.

Line No.	Description	Amount
	A	B
1	Sugar Creek Plant Cost (NBV at December 1, 2008)	\$ 322,446,401
2	Annual Interest Rate	<u>6.50%</u>
3	Annual Deferred Carrying Charges	\$ <u>20,959,016</u>
4	Months (December 1, 2008 through December 31, 2009)	<u>13</u>
5	Deferred Carrying Charges for Sugar Creek (Line 3 divided by 12, multiplied by 13)	\$ <u>22,705,601</u>
6	Amortization Period in Years Per Cause No. 43396	<u>5</u>
7	Increase in Pro Forma Test Year Depreciation and Amortization Expense	<u>\$ 4,541,120</u>
8		
	Deferred Carrying Charges for Sugar Creek	\$ 22,705,601
	Amortization Period in Years Per Cause No. 43396	<u>5</u>
	Increase in Pro Forma Test Year Depreciation and Amortization Expense	<u>\$ 4,541,120</u>

Northern Indiana Public Service Company
Sugar Creek
Pro Forma Adjustment to Taxes Other Than Income
Twelve Months Ended December 31, 2007

This pro forma adjustment increased 2007 test year taxes other than income to adjust for electric property taxes for Sugar Creek for December 2008 through November 2009.

Line No.	Description	Amount
	A	B
1	Sugar Creek Property Taxes: December 2008 - November 2009	\$ 697,593
2		\$ -
3	Increase Pro Forma Test Year Taxes Other Than Income	<u>\$ 697,593</u>

Northern Indiana Public Service Company
Pro Forma Adjustment to Income Taxes
Twelve Months Ended December 31, 2007

This pro forma adjustment decreased 2007 test year income taxes to adjust for the pro forma level of pre-tax income utilization of the interest synchronization method.

Line No.	Description	Amount
	A	B
1	Decrease in Pro Forma Test Year Income Taxes	\$ (11,868,829)

Northern Indiana Public Service Company
Pro Forma Adjustment Based on Proposed Rates
Twelve Months Ended December 31, 2007

This proposed rates adjustment increased the 2007 test year revenue requirement based on an 8.34% rate of return on a net original cost rate base of \$2,665,437,036

Line No.	Description A	Amount B
1	Actual Net Operating Income	\$ 173,056,305
2	Required Net Operating Income	<u>\$ 223,095,808</u>
3	Surplus (Deficit)	\$ (50,039,503)
4	Tax Gross-Up Rate	<u>1.713542749</u>
5	Increase in Pro Forma Test Year Revenue Requirement Based on Proposed Rates	<u>\$ (85,744,828)</u>

Northern Indiana Public Service Company
Pro Forma Adjustment Based on Proposed Rates
Twelve Months Ended December 31, 2007

This proposed rates adjustment increased 2007 test year O&M expense to reflect the level of uncollectible accounts based on the proposed revenue requirement increase.

Line No.	Description	Amount
	A	B
1	Gross Margin Deficiency	\$ 85,744,828
2	Uncollectible Accounts Rate	<u>0.226593%</u>
3	Increase in Pro Forma Test Year O&M Expense Based on Proposed Rates	<u>\$ 194,292</u>

Northern Indiana Public Service Company
Pro Forma Adjustment Based on Proposed Rates
Twelve Months Ended December 31, 2007

This proposed rates adjustment increased the 2007 test year taxes other than income to reflect the Indiana utility receipts tax associated with the proposed revenue requirement increase.

Line No.	Description A	Amount B
1	Gross Margin Deficiency	\$ 85,744,828
2	IURT Rate	<u>1.40%</u>
3	Increase in Pro Forma Test Year Taxes Other Than Income Based on Proposed Rates	<u>\$ 1,200,428</u>

Northern Indiana Public Service Company
Pro Forma Adjustment Based on Proposed Rates
Twelve Months Ended December 31, 2007

This proposed rates adjustment increased the 2007 test year taxes other than income to reflect the public utility fees associated with the proposed revenue requirement increase.

Line No.	Description A	Amount B
1	Gross Margin Deficiency	\$ 85,744,828
2	Public Utility Fee Rate	0.1204%
3	Increase in Pro Forma Test Year Taxes Other Than Income Based on Proposed Rates	<u>\$ 103,237</u>

Northern Indiana Public Service Company
Pro Forma Adjustment Based on Proposed Rates
Twelve Months Ended December 31, 2007

This proposed rates adjustment increased the 2007 test year income taxes to reflect the federal and state income taxes applied to the proposed revenue requirement increase.

Line No.	Description A	Amount B
1	Gross Margin Deficiency	\$ 85,744,828
2	Effective Federal Tax Rate	31.423875%
3	Effective State Tax Rate	8.470506%
4	Increase in Pro Forma Test Year Income Taxes Based on Proposed Rates	<u>\$ 34,207,368</u>

Rate Base
Actual, Jurisdictional, As Updated
Twelve Months Ended December 31, 2007

Line No.	Description	Actual	Updates	Total
	A	B	C	D
1	RATE BASE			
2	Utility Plant	\$ 4,967,588,851	\$ 237,989,897	\$ 5,205,578,748
3	Common Allocated	213,322,211	1,180,329	214,502,540
4	Less Disallowed Plant: Unit 17	<u>31,733,655</u>	<u>-</u>	<u>31,733,655</u>
5	Total Utility Plant	5,149,177,407	239,170,226	5,388,347,633
6	Accumulated Depreciation and Amortization	(2,883,773,255)	83,392,777	(2,800,380,478)
6a	SC Accumulated Depreciation and Amortization	-	(5,618,432)	(5,618,432)
7	Common Allocated	(97,073,378)	(1,335,790)	(98,409,168)
8	Less Disallowed Plant: Unit 17	<u>(27,399,652)</u>	<u>-</u>	<u>(27,399,652)</u>
9	Total Accumulated Depreciation and Amortization	<u>(2,953,446,981)</u>	<u>76,438,555</u>	<u>(2,877,008,426)</u>
10	Net Utility Plant	2,195,730,426	315,608,781	2,511,339,207
11	Pure Air Deferred Charges	526,218	-	526,218
12	Unit 17 Depreciation	542,928	-	542,928
13	Unit 18 Depreciation	5,206,694	-	5,206,694
14	Unit 18 Carrying Charges	16,132,193	-	16,132,193
15	Prepaid Pension Asset	25,705,004	-	25,705,004
16	Materials & Supplies	46,907,735	-	46,907,735
16a	Materials & Supplies	-	1,495,291	1,495,291
17	Production Fuel	<u>57,566,559</u>	<u>-</u>	<u>57,566,559</u>
18	Total Rate Base	<u>\$ 2,348,317,757</u>	<u>\$ 317,104,072</u>	<u>\$ 2,665,421,829</u>
19	REQUIRED NET OPERATING INCOME			
20	Total Rate Base			\$ 2,665,421,829
21	Rate of Return			<u>8.37%</u>
22	Required Net Operating Income			<u>\$ 223,095,808</u>

Summary of Rate Base Updates
December 31, 2007 As Updated

Line No	Description	Exhibit No.	Debit	Credit
	A	B	C	D
1	Rate Base Updates:			
2	DH Mitchell Plant Retirement			
3	Mitchell Units 4, 5, 6, 11, and 9A - Plant-in-Service	RB - 1	\$ -	\$ 175,909,015
4	Mitchell Units 4, 5, 6, 11 and 9A - Accumulated Depreciation	RB - 2	\$ 178,072,088	\$ -
5	Michigan City 2&3 Plant Retirement			
6	MC Units 2 & 3 - Plant-in-Service	RB - 3	\$ -	\$ 19,395,755
7	MC Units 2 & 3 - Accumulated Depreciation	RB - 4	\$ 18,096,416	\$ -
8	Seven Factor Test			
9	Gross Plant	RB - 5	\$ 123,243,367	\$ 123,243,367
10	Accumulated Depreciation and Amortization	RB - 6	\$ 48,919,630	\$ 48,919,630
11	All Other Transfers / Corrections			
12	Electric			
13	Gross Plant	RB - 7	\$ 148,573,386	\$ 43,343,552
14	Accumulated Depreciation	RB - 8	\$ 17,622,081	\$ 130,397,808
15	Common			
16	Gross Plant	RB - 9	\$ 1,180,329	\$ -
17	Accumulated Depreciation	RB - 10	\$ -	\$ 1,335,790
18	Sugar Creek Material and Supplies	RB - 11	\$ 1,495,291	
19	Sugar Creek Gross Plant	RB - 12	\$ 328,064,833	
20	Accumulated Depreciation	RB - 13		\$ 5,618,432
21	Total Rate Base Updates		\$ 865,267,421	\$ 548,163,349
22	Net Increase / (Decrease)		\$ 317,104,072	

Capital Structure
December 31, 2007 As Adjusted

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	\$ 1,395,245,772	49.94%	12.00%	5.99%
2	Long-Term Debt	\$ 906,997,137	32.47%	6.56%	2.13%
3	Customer Deposits	\$ 63,684,199	2.28%	6.00%	0.14%
4	Deferred Income Taxes	\$ 294,780,249	10.55%	0.00%	0.00%
5	Post-Retirement Liability	\$ 102,637,766	3.66%	0.00%	0.00%
6	Post-1970 ITC	\$ 30,350,460	1.09%	9.86%	0.11%
7	Totals	\$ 2,793,695,583	100.00%		8.37%

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
8	Common Equity	\$ 1,395,245,772	60.60%	12.00%	7.28%
9	Long-Term Debt	\$ 906,997,137	39.40%	6.56%	2.58%
10	Totals	\$ 2,302,242,909	100.00%		9.87%

Capital Structure
December 31, 2007 As Adjusted

Line No.	Description A	2007 Actuals B	Debit C	Credit D	Ref. E	Pro Forma Balance F	Percent of Total G	Cost H	Weighted Average Cost I
1	Common Equity	\$ 1,394,077,564	\$ -	\$ 1,168,208	CS - 1	\$ 1,395,245,772	49.94%	12.00%	5.99%
2	Long-Term Debt	\$ 746,997,137	\$ -	\$ 160,000,000	CS - 2	\$ 906,997,137	32.47%	6.56%	2.13%
3	Customer Deposits	\$ 63,684,199	\$ -	\$ -		\$ 63,684,199	2.28%	6.00%	0.14%
4	Deferred Income Taxes	\$ 293,984,257	\$ -	\$ 795,992	CS - 3	\$ 294,780,249	10.55%	0.00%	0.00%
5	Retirement Liability	\$ 112,678,496	\$ 10,040,730	\$ -	CS - 4	\$ 102,637,766	3.66%	0.00%	0.00%
6	Post-1970 ITC	\$ 30,350,460	\$ -	\$ -		\$ 30,350,460	1.09%	9.86%	0.11%
7	Totals	\$ 2,641,772,113	\$ 10,040,730	\$ 161,964,200		\$ 2,793,695,583	100.00%		8.37%

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED SUPPLEMENTAL DIRECT TESTIMONY

OF

ROBERT D. CAMPBELL

SENIOR VICE PRESIDENT, HUMAN RESOURCES

VERIFIED SUPPLEMENTAL DIRECT TESTIMONY OF ROBERT D. CAMPBELL

1 **Q1. Please state your name and business address.**

2 A1. My name is Robert D. Campbell, and my business address is 801 E. 86th Avenue,
3 Merrillville, Indiana 46410

4 **Q2. By whom are you employed and in what capacity?**

5 A2. I am employed by NiSource Corporate Services Company as Senior Vice President,
6 Human Resources.

7 **Q3. Did you previously submit Prepared Direct Testimony as a part of the Case-In-**
8 **Chief of Petitioner Northern Indiana Public Service Company ("NIPSCO") filed**
9 **with the Commission in this Cause on August 29, 2008?**

10 A3. Yes. My Prepared Direct Testimony has been marked as Petitioner's Exhibit RDC-1.

11 **Q4. What is the purpose of your Supplemental Direct Testimony?**

12 A4. The purpose of my Supplemental Testimony is to provide the Commission with information
13 about the adjustment to test year medical expense sponsored by Petitioner's Witness Linda
14 E. Miller in her Revised Direct Testimony.

15 **Q5. Why is this adjustment to test year medical expense needed?**

16 A5. During 2007, a portion of NIPSCO's retiree health care benefits was incorrectly
17 classified as active employee health care benefits expense. As a self-insured entity,
18 NiSource is responsible for payment of claims related to both active employees and
19 retired employees. These charges were incorrectly classified because Anthem, the third

1 party provider administering NiSource's medical-related claims, changed its coding
2 structure beginning January 1, 2007 for differentiating some active and retiree claims.
3 One of the codes formerly used to classify active employee claims was changed so that it
4 now classifies retiree claims. These codes are used to input data contained in a monthly
5 report provided to NiSource's Human Resources department to detail the claims paid for
6 NiSource. When Anthem performed its code change at the end of 2006, mapping for
7 those coded charges was not updated. Because the code was not changed, \$10,040,730
8 was incorrectly booked to NIPSCO gas and electric as active employee benefits expense
9 rather than as retiree benefits claims.

10 **Q6. When was this issue discovered?**

11 A6. In December 2007, during the preparation of NiSource's financial statements for the year
12 ended December 31, 2007, a fluctuation in the recording between active and retiree
13 claims for NIPSCO and other NiSource subsidiaries was noted by NiSource's financial
14 reporting department. Although the internal investigation of the fluctuation was
15 immediately begun, the misclassification could not be identified and traced back to the
16 Anthem coding change until the third quarter of 2008 -- after the case-in-chief in this
17 proceeding was filed.

18 **Q7. What is the amount of the adjustment?**

19 A7. As discussed in NIPSCO witness Linda E. Miller's Revised Testimony, the adjustment to
20 test year medical expense for NIPSCO's electric operation is a reduction of \$5,276,650.

1 **Q8. Does this conclude your Supplemental Direct Testimony?**

2 **A8. Yes.**

VERIFICATION

I, Robert D. Campbell, Senior Vice President Human Resources for NiSource Corporate Services, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.



Robert D. Campbell

Date: December 18, 2008

Petitioner's Exhibit JMO-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

JOHN M. O'BRIEN

ASSISTANT CONTROLLER OF TAXES

SPONSORING PETITIONER'S EXHIBIT JMO-2 (Revised)

Revised

1 **Q9. Have you prepared an exhibit relating to those subjects?**

2 **A9. Yes.** I have prepared Petitioner's Exhibit JMO-2 (Revised) which provides a detailed
3 explanation of the calculation of the federal and state tax expense amounts included in
4 Ms. Miller's accounting exhibits.

5 **I. FEDERAL INCOME TAX EXPENSE**

6 **Q10. Please describe the basic components of federal income tax expense reflected in Ms.**
7 **Miller's accounting exhibits**

8 **A10.** At its most basic level, the quantification of federal income tax expense begins with the
9 application of the 35% federal income tax rate applied to pro forma net operating income
10 less interest expense. This amount was adjusted to account for the following five issues:

- 11 (i) Adjustment to reflect the various impacts for the differences between the use of
12 accelerated depreciation for income tax return purposes and straight line
13 depreciation in determining tax expense for regulatory and book purposes;
14 (ii) Adjustment to reflect certain limitations on the amount of the federal income tax
15 deduction that may be taken on certain categories of expense;
16 (iii) Reduction in tax expense for Amortization of Investment Tax Credits;
17 (iv) Reduction in tax expense for Section 199 Manufacturing Credit; and
18 (v) Reduction in tax expense for allocation of parent company (NiSource) interest
19 expense.

20 **Q11. How is the amount of the interest expense deduction calculated?**

1 A11. The interest expense deduction was determined using the interest synchronization
2 method. Under this method, the interest expense deduction is calculated to be
3 ~~\$50,341,823~~57,306,569 by multiplying NIPSCO's original cost electric rate base (shown
4 in Ms. Miller's exhibits to be ~~\$2,341,480,136~~2,665,421,829) by the weighted cost of debt
5 computed from a capital structure that excludes investment tax credits (2.15%). This
6 method results in an appropriate level of interest to reflect for purposes of setting electric
7 rates.

8 **Q12. Would you please explain the issues arising from the use of accelerated depreciation**
9 **for income tax purposes?**

10 A12. On the federal income tax return, depreciation expense is deducted using accelerated
11 rates provided for in the Internal Revenue Code. Accelerated depreciation for tax
12 purposes is intended to provide companies with an incentive to make investments that
13 improve the economy and provide other public benefits. For regulatory and book
14 purposes, the depreciation expense deduction is calculated on a straight line basis over
15 the life of the property using depreciation rates approved by the Commission. The
16 regulatory and book treatment included in the income tax component of cost of service is
17 referred to as the normalization method of accounting and is required by the Internal
18 Revenue Code. The difference between accelerated and normalized depreciation is a
19 timing (or temporary) difference – the same amount of depreciation expense ultimately
20 will be deducted for tax and book purposes, but the depreciation expense deduction will
21 be reflected in different time periods. These timing differences are accounted for on

1 addition, NIPSCO has little if any property in any tax districts other than Lake and St.
2 Joseph Counties that currently would receive any benefit from the circuit breakers.

3 House Enrolled Act 1001 also included a provision stating that the owner of an industrial
4 plant in Jasper County with an assessed value that exceeds 20% of the total taxable
5 assessed value in the county for 2006 is not entitled to receive local property tax
6 replacement credits otherwise payable from Local Option Income Taxes ("LOIT"). The
7 only taxpayer impacted by this provision is NIPSCO caused by its ownership of the R.
8 M. Schahfer Generating Station. The Legislative Services Agency has estimated that
9 NIPSCO will lose \$1.2 million of credits it would have been entitled to absent this
10 provision.

11 The shifting of funding and responsibilities from local to state government will occur
12 primarily through an increase in the state sales tax rate from 6% to 7% effective April 1,
13 2008.

14 At this point, the Company cannot estimate the impact of the recent tax changes in
15 property taxes in Indiana on its 2008 and future property tax expense. Given this
16 uncertainty, NIPSCO is not proposing an adjustment related to House Enrolled Act 1001.

17 **Q29. Have you calculated the Company's property taxes that will be incurred in**
18 **connection with the Company's newly acquired Sugar Creek generating facility?**

19 ~~A29. Yes, the Company has included \$1,132,243 for property taxes based on the June 2010~~
20 ~~through May 2011 projected liability. The amounts have been adjusted by the abatement~~

Revised

percentage on the taxable value of the plant for the 2010-2011 period. Yes. The level of property taxes for the Sugar Creek generating facility is \$697,593, which is an annual estimate for the period December 1, 2008 through November 30, 2009.

IV. UTILITY RECEIPTS TAX

Q30. Please explain how the Utility Receipts Tax is computed.

A30. NIPSCO is subject to a 1.4% Utility Receipts Tax on all receipts except sales for resale. For the year 2007, the Company recorded Utility Receipts Taxes of \$18,372,838. On a pro forma basis under the Company's present rates, the operating revenues quantified by Ms. Miller would result in Utility Receipts Tax of \$11,905,630, requiring a downward adjustment of \$6,467,208. The major reason for this significant adjustment is the Company's proposal to remove the cost of fuel and purchased power from base rates as explained by NIPSCO Witness Frank A. Shambo. If the cost of fuel and purchased power is to be recovered entirely through trackers, then the Utility Receipts Tax associated with recovering the cost of fuel and purchased power during the test year should also be removed from base rates. The Utility Receipts Tax associated with the cost of fuel and purchased power will be recovered through the Company's separate fuel adjustment clause and tracker filings.

V. SUMMARY

Q31. Please describe Petitioner's Exhibit JMO-2.

A31. Schedule 1 of Petitioner's Exhibit JMO-2 (Revised) shows the derivation of the Company's federal and state income tax expense reflecting each of the adjustments

Revised

1 | previously described in my testimony. Schedule 2 of Petitioner's Exhibit JMO-2
2 | (Revised) shows the calculation of the effect on the Company's tax expense of the
3 | adjustments for excess and deferred taxes, the limitation on the deductibility of meals and
4 | entertainment expenses, the investment tax credit amortization, the Section 199
5 | deduction, the parent company interest allocation and the Indiana Utility Receipts Tax.

6 | **Q32. Are the tax expense adjustments reflected in Ms. Miller's exhibits correct and**
7 | **consistent with the matters described above?**

8 | A32. Yes, they are.

9 | **Q33. Does this conclude your prepared direct testimony?**

10 | A33. Yes, it does.

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

JOHN M. O'BRIEN

ASSISTANT CONTROLLER OF TAXES

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16 referred to as the normalization method of accounting and is required by the Internal
17 Revenue Code. The difference between accelerated and normalized depreciation is a
18 timing (or temporary) difference – the same amount of depreciation expense ultimately
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13 2008.

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16 uncertainty, NIPSCO is not proposing an adjustment related to House Enrolled Act 1001.

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18 **connection with the Company's newly acquired Sugar Creek generating facility?**

1 A29. Yes. The level of property taxes for the Sugar Creek generating facility is \$697,593,
2 which is an annual estimate for the period December 1, 2008 through November 30,
3 2009.

4 **IV. UTILITY RECEIPTS TAX**

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11 Company's proposal to remove the cost of fuel and purchased power from base rates as
12 explained by NIPSCO Witness Frank A. Shambo. If the cost of fuel and purchased
13 power is to be recovered entirely through trackers, then the Utility Receipts Tax
14 associated with recovering the cost of fuel and purchased power during the test year
15 should also be removed from base rates. The Utility Receipts Tax associated with the
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18 **V. SUMMARY**

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6 **Q32. Are the tax expense adjustments reflected in Ms. Miller's exhibits correct and**
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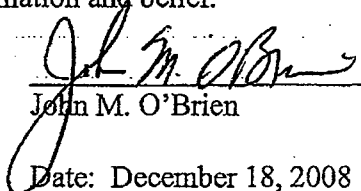
8 A32. Yes, they are.

9 **Q33. Does this conclude your prepared direct testimony?**

10 A33. Yes, it does.

VERIFICATION

I, John M. O'Brien, Assistant Controller of Taxes, for NiSource Corporate Services Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.



John M. O'Brien

Date: December 18, 2008

Northern Indiana Public Service Company
Income Tax Expense Included In Pro Forma Income

<u>Description</u>	<u>Amount</u>
Net Operating Income	173,056,305
Plus: Income Taxes Included in Net Operating Income	78,229,647
Net Operating Income Before Taxes	251,285,952
Interest Synchronization Deduction	(57,306,569)
Federal Taxable Income Before State Tax Deduction	193,979,383
Less: State Income Taxes at 8.5%	16,488,248
Federal Taxable Income	177,491,135
Federal Income Taxes at 35%	62,121,897
Other Components of Income Tax Expense	
Federal Income Taxes	
Net Deficient Deferred Taxes	3,312,705
Permanent Differences: Meals	135,084
Investment Tax Credit Amortization	(4,556,906)
Section 199 Deduction	(3,256,642)
Parent Company Tax Benefit of Interest Expense	(1,122,881)
Subtotal	<u>(5,488,640)</u>
State Income Taxes	
Net Deficient Deferred Taxes	4,429,032
Permanent Differences: Meals	21,324
Permanent Differences: Utility Receipts Tax	657,786
Subtotal	<u>5,108,142</u>
Summary:	
Federal Income Taxes	56,633,257
State Income Taxes	21,596,390
Total Income Taxes Included In Pro Forma Calculation	<u><u>78,229,647</u></u>

**Northern Indiana Public Service Company
Adjustments to Income Tax Allowance**

<u>Description</u>	<u>Balance at December 31, 2007</u>	<u>Projected at December 31, 2008</u>	<u>Amortization or Tax Allowance</u>
<u>Excess & Deficient Deferred Taxes</u>			
Net Excess for Method and Life Differences	(17,658,545)	(14,726,827)	(2,931,718)
Deficiency for Flow Through and AFUDC Equity	35,357,171	29,112,748	6,244,423
Deficiency for State Income Taxes	32,224,744	27,795,712	4,429,032
Total	49,923,370	42,181,633	7,741,737

	<u>Projected 2008 Non-Deductible Exp.</u>	<u>Tax Rate</u>	<u>Tax Allowance</u>
<u>Permanent Differences</u>			
Meals & Entertainment (Federal)	385,953	35%	135,084
Meals & Entertainment (State net of Federal)	385,953	5.525%	21,324

	<u>Balance at December 31, 2007</u>	<u>Projected at December 31, 2008</u>	<u>Amortization or Tax Allowance</u>
<u>Investment Tax Credit Amortization</u>			
Vintage Years 1978-1988 (account 255)	(25,019,476)	(20,462,570)	(4,556,906)

	<u>Projected Taxable Generation Income</u>	<u>Deduction Percent</u>	<u>Tax Allowance</u>
<u>Section 199 Deduction</u>			
Taxable Income	155,078,183	-6%	(9,304,691)
Tax Rate			35%
Tax Allowance			(3,256,642)

	<u>Projected Allocation</u>	<u>Tax Allowance</u>
<u>Parent Company Tax Benefit of Interest Expense</u>		
Interest Expense on Parent / NiSource Finance	14,132,154	
Percent Allocated to NIPSCO Based on Investment	26.3055%	
Subtotal	3,717,534	
Electric Percentage	86.30%	
Tax Loss Allocated to Electric	3,208,232	
Tax Rate	35%	
Tax	(1,122,881)	(1,122,881)

	<u>Non-Deductible Expenses</u>	<u>Tax Rate</u>	<u>Tax Allowance</u>
<u>State Income Tax Allowance for URT</u>			
Projected URT Expense	11,905,630	8.5%	1,011,979
Federal Benefit			(354,193)
Tax Allowance			657,786

Total Federal and State Tax Adjustments to Statutory Rate	(380,498)
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NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

PHILIP W. PACK

DIRECTOR, GENERATION SUPPORT SERVICES AND MAJOR
PROJECTSMANAGER, MAJOR PROJECTS & RESOURCE
DEVELOPMENT

SPONSORING PETITIONER'S EXHIBITS PWP-2 THROUGH PWP-5

VERIFIED DIRECT TESTIMONY OF PHILIP W. PACK

Q1. Please state your name and business address.

A1. My name is Philip W. Pack. My business address is 2755 Raystone Drive, Valparaiso, Indiana, 46383.

Q2. By whom are you employed and in what capacity?

A2. I am employed by Northern Indiana Public Service Company ("NIPSCO" or the "Company") as Director, Generation Support Services and Manager, Major Projects & Resource Development. In this role, I am responsible for management of capital and operation and maintenance ("O&M") projects throughout NIPSCO's generation operations.

Q3. What is your educational background?

A3. I received a bachelor degree in Mechanical Engineering from Western Michigan University in 1980, and I am a Licensed Professional Engineer in the State of Indiana.

Q4. Please describe your professional experience.

A4. I began my employment with NIPSCO in 1981 in the Results Department. My experience includes various technical and management positions in Electric Production prior to my promotion to Operations Manager of Bailly Generating Station in 2000, Compliance Projects Manager in March 2002, ~~and Manager, Major Projects and Resource Development in June 2006~~ and Director, Generation Support Services and Major Projects in September 2008.

Q5. Have you previously testified before this or any other regulatory commission?

A5. Yes, I have testified before the Indiana Utility Regulatory Commission ("Commission") on environmental matters for NIPSCO in several proceedings including Cause Nos. 42150, 43144 and 43371.

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to: (1) describe NIPSCO's generation fleet and changes to that fleet, including the retirement and demolition of the D. H. Mitchell Generating Station ("Mitchell") and Michigan City Generating Station ("Michigan City") Units 2 and 3; (2) support an operation and maintenance ("O&M") expense adjustment to reflect increases in contract labor costs shown on Petitioner's Exhibit LEM-2; and (3) explain adjustments to NIPSCO's environmental cost recovery mechanisms.

I. NIPSCO'S GENERATION FLEET

Q7. Are you generally familiar with NIPSCO's generating facilities?

A7. Yes, I am.

Q8. Please generally describe NIPSCO's generation fleet at the end of the test year.

A8. The NIPSCO generating facilities have a total capacity of 2,787 megawatts ("MW") and consist of six (6) separate generation sites, including the Company's R.M. Schahfer Generating Station, Michigan City, Bailly Generating Station, Mitchell and two (2) hydroelectric generating sites near Monticello, Indiana. Of the total capacity, 92.4% is from coal-fired units, 7.3% is from natural gas-fired units and 0.3% is from hydroelectric

1 units. Petitioner's Exhibit PWP-2 provides a summary of the generating facilities
2 operated by NIPSCO.

3 **Q9. Has NIPSCO made any capital investment in generation facilities not included in**
4 **test year results?**

5 A9. Yes. As NIPSCO Witness Bradley K. Sweet explains, on May 30, 2008, NIPSCO
6 acquired Sugar Creek Power Company, LLC which then owned a 535 MW combined
7 cycle gas turbine ("CCGT" or "Sugar Creek") located near Terre Haute, Indiana. Sugar
8 Creek Power Company, LLC was then merged into NIPSCO. As a result of this
9 transaction, NIPSCO now owns the CCGT. Sugar Creek is configured with two
10 combustion gas turbines ("CTs") and one steam turbine generator ("STG"). Sugar Creek
11 has the ability to interconnect with either the Midwest Independent Transmission System
12 Operator, Inc. (the "Midwest ISO") or the PJM Interconnection, LLC ("PJM").

13 **Q10. Did NIPSCO receive a Certificate of Public Convenience and Necessity ("CPCN")**
14 **from the Commission prior to acquiring Sugar Creek?**

15 A10. Yes. The Commission granted NIPSCO a CPCN for the acquisition of Sugar Creek in its
16 May 28, 2008 Order in Cause No. 43396 (the "CPCN Order").

17 **Q11. Which Regional Transmission Organization is Sugar Creek interconnected to now?**

18 A11. As of December 1, 2008, Sugar Creek is a Designated Network Resource in the Midwest
19 ISO. Independent Transmission System Owners, Inc.

20 **Q12. Can NIPSCO determine the non-fuel O&M expenses associated with Sugar Creek?**

1 A12. Yes. NIPSCO has actual O&M expenses from the last 12 months including six months
2 under NIPSCO ownership. The actual O&M expenses from the last 12 months were
3 \$6,056,2896,457,575 and were \$2,959,6502,992,450 for the last 6 months under NIPSCO
4 ownership. I have reviewed this information and believe it to be reliable. The projected
5 non-fuel O&M expense to operate Sugar Creek from December 1, 2008 through
6 November 30, 2009 is \$5,919,2995,984,899. Attached hereto as Petitioner's Exhibit
7 PWP-3 (Revised) is a breakdown of the O&M expenses for Sugar Creek. This
8 adjustment does not include tax expense associated with Sugar Creek, which is addressed
9 by NIPSCO Witness John O'Brien.

10 **Q13. How did NIPSCO calculate the O&M expenses for Sugar Creek for the twelve**
11 **months commencing December 1, 2008?**

12 A13. NIPSCO used the actual O&M expenses for the last 6 months and doubled the expense
13 value to obtain the 12 month projection. This method to determine the O&M
14 requirement is considered conservative as the value is less than the last 12 month actual
15 O&M expenses. The variable O&M expenses associated with the Long Term Service
16 Agreement ("LTSA") are included in the O&M expenses projection. NIPSCO did not
17 include fixed O&M expenses associated with the LTSA overhaul costs as the overhauls
18 will not occur for several years.

19 ~~**Q11.Can NIPSCO determine the O&M expenses associated with Sugar Creek?**~~

20 ~~A11.Yes. NIPSCO has access to the 2007 Sugar Creek historical O&M and variance reports~~
21 ~~from May through December, 2007 and the 2008 annual budget. The 2007 (8 months)~~

Revised

1 ~~actual O&M was \$5,378,997 compared to a budget of \$5,770,339. The 2008 Sugar~~
2 ~~Creek annual budget includes budgeted O&M expense of \$7,677,900. I have reviewed~~
3 ~~this information and believe it to be reliable. Using 2007 data, NIPSCO has calculated~~
4 ~~the projected non fuel O&M expense Sugar Creek will incur for the first twelve month~~
5 ~~period the unit is dispatched into the Midwest ISO. The projected O&M cost to operate~~
6 ~~Sugar Creek from June 1, 2010 through May 31, 2011 is \$9,388,421. Attached to my~~
7 ~~testimony as Petitioner's Exhibit PWP-3 is a breakdown of the O&M costs for Sugar~~
8 ~~Creek.~~

9 ~~**Q12. How did NIPSCO calculate the O&M costs for Sugar Creek for the twelve months**~~
10 ~~**commencing June 1, 2010?**~~

11 ~~A12. NIPSCO used the historical O&M costs for Sugar Creek and input that data into PROMOD~~
12 ~~to develop the O&M expenses for this period. PROMOD is a computer program that~~
13 ~~uses historic operating costs, unit heat rate and expected market conditions to develop~~
14 ~~generation projections for each NIPSCO unit. The use of PROMOD allows NIPSCO to~~
15 ~~account for the variable O&M cost difference between Sugar Creek's dispatch into PJM~~
16 ~~and the Midwest ISO. The O&M cost uses historical data for the fixed costs and adds a~~
17 ~~five year amortization of the gas turbine Long Term Service Agreement ("LTSA")~~
18 ~~overhaul costs (\$1,524,405).~~

19 **Q14. Please explain the LTSA for Sugar Creek.**

20 A14. The LTSA is a contract with General Electric International, Inc. to perform routine
21 maintenance on the Sugar Creek facility turbines and generators. The LTSA was

1 executed prior to NIPSCO's acquisition of the Sugar Creek facility and NIPSCO assumed
2 the LTSA as part of the merger. Major maintenance is performed at intervals determined
3 by the number of operating starts and hours. NIPSCO's due diligence of the Sugar Creek
4 facility compared the confidential prices of the LTSA to market prices and determined
5 the LTSA has favorable economic terms.

6 **Q15. Did NIPSCO experience operational constraints in 2007 that reduced the operating**
7 **hours of any of its generating units?**

8 A15. Yes. In 2007, NIPSCO's generation fleet experienced three unusually long outages. Unit
9 7 experienced a planned outage to combine maintenance with the installation of
10 environmental control equipment. The Unit was scheduled for the replacement of the
11 boiler cyclones, various boiler pressure parts, a turbine overhaul and the installation of a
12 Selective Catalytic Reduction ("SCR") system for NOx reduction. Due to the amount of
13 work that was scheduled, two outages totaling 25 weeks were required to prevent
14 interference among projects. Installation of an SCR at Unit 7 is a one time event that is
15 not anticipated to occur again. Unit 10 experienced a forced outage on February 1, 2007.
16 This outage was caused by a failure of the rotor stub shaft bolting resulting in extensive
17 turbine damage. This outage lasted through the end of 2007 and into 2008 due to
18 difficulties obtaining replacement components. Unit 16A also experienced a long forced
19 outage beginning August 1, 2007. The outage was caused by a failure of blade locking
20 pins that caused extensive damage to the compressor section of the unit. Damage of this
21 kind is not typical and would not be something I would expect to occur in the future. The

1 outage continued throughout the end of the 2007 year and into 2008. Due to these
2 unusual constraints, the 2007 operational availability for Units 7, 10 and 16A should be
3 adjusted as described in Mr. Sweet's testimony.

4 **II. DEMOLITION OF CERTAIN UNITS**

5 **Q16. What generation facilities is NIPSCO retiring?**

6 A16. NIPSCO is retiring Mitchell and Michigan City Units 2 and 3.

7 **Q17. Please describe Mitchell.**

8 A17. Mitchell has four coal fired units which range in age from 38 to 52 years old. At
9 shutdown in 2002, Units 5, 6, and 11 burned low sulfur sub-bituminous coal from the
10 Powder River Basin in Wyoming. Unit 4 had the capability to burn either natural gas or
11 Powder River Basin coal. The net capacity of the four coal fired units totaled 485 MW.
12 As indicated in Mr. Sweet's testimony, Units 4, 5, 6 and 11 were indefinitely shutdown in
13 January 2002. Unit 9 is a natural gas combustion turbine capable of 17 MW of output.

14 **Q18. Why is NIPSCO retiring Mitchell?**

15 A18. Mr. Sweet describes in more detail the reasons NIPSCO no longer intends to operate
16 Mitchell. The restart of the shutdown Mitchell units was considered in NIPSCO's 2007
17 Integrated Resource Plan ("IRP") modeling as a supply-side option. The IRP suggested
18 the Mitchell restart options should be abandoned in lieu of purchasing one or more
19 CCGTs because of the \$587,500,000 cost to restart Mitchell. As indicated in Table 7-8
20 (page 145) of the 2007 NIPSCO IRP, the New Energy "Strategist" Model never selected

1 a Mitchell reactivation option as a low-cost supply-side resource in the next 20 years.
2 NIPSCO will retire Mitchell, demolish the facilities and remediate the site to industrial
3 condition.

4 **Q19. What is generally involved in demolishing and remediating Mitchell?**

5 A19. As described in the demolition cost study prepared by Burns & McDonnell and submitted
6 as Petitioner's Exhibit VFR-3, Mitchell's demolition will include removal of equipment
7 at the site, as well as any building structures, but leaving the below grade piping and
8 wiring in place. Foundations will be filled to grade and the coal pile and ash ponds will
9 be covered with soil and seeded. Burns & McDonnell estimates that remediating
10 Mitchell will take approximately 30 months.

11 **Q20. Please describe the Michigan City Units 2 and 3?**

12 A20. The two natural gas fired units at Michigan City station range in age from to 57 to 58
13 years old. The net capacity of the units totaled 120 MW. The boilers for Units 2 and 3
14 were coal-fired until 1988 when the operation was limited to natural gas only to reduce
15 SO₂ emissions from the plant. As indicated by Mr. Sweet, Michigan City Unit 2 and 3
16 were indefinitely shutdown in June 2005 due to the condition of the boilers.

17 **Q21. Why is NIPSCO retiring the Michigan City Units 2 and 3?**

18 A21. Mr. Sweet explains why NIPSCO is retiring Michigan City Units 2 and 3. In general
19 terms, NIPSCO has determined the units are at the end of their useful life due to
20 extensive tube corrosion damage to boiler walls and cyclones. Additionally, the turbines

1 and auxiliary systems have extensive wear due to their 50 plus years of service. NIPSCO
2 will retire Units 2 and 3 and demolish the facilities in the manner described in the Burns
3 & McDonnell demolition studies marked as Petitioner's Exhibit VFR-6.

4 **Q22. What is generally involved in demolishing the Michigan City Units 2 and 3?**

5 A22. As described in the Burns & McDonnell demolition study, the demolition of Units 2 and
6 3 includes removal of all associated equipment, piping, wiring and HVAC equipment not
7 necessary for continued operations of Michigan City Unit 12. The shell of the building
8 would remain in-place. Burns & McDonnell estimates demolishing Michigan City Units
9 2 and 3 will take approximately 22 months.

10 **Q23. Will any Michigan City units remain in service after the retirement of Units 2 and**
11 **3?**

12 A23. Yes. Michigan City Unit 12 will remain a supply-side resource for NIPSCO and will
13 remain in service.

14 **Q24. Are you familiar with the information relied upon by Burns & McDonnell in the**
15 **preparation of the demolition studies and sponsored by Mr. Ranaletta?**

16 A24. Yes, I am. The Burns & McDonnell demolition cost studies sponsored by Mr.
17 Ranaletta's testimony rely on NIPSCO site and equipment drawings, historic
18 contamination associated with Solid Waste Management Units and asbestos remediation
19 estimates prepared by NIPSCO's asbestos contractor Insulco. Based upon my knowledge

1 and review of these documents, this information can be relied upon by Burns &
2 McDonnell in the preparation of its demolition cost studies.

3 **III. GENERATION O&M EXPENSE ADJUSTMENT**

4 **Q25. Are you supporting any adjustments to O&M for generation?**

5 A25. Yes. I recommend an upward adjustment to O&M generation maintenance expense to
6 reflect increases in contract labor costs.

7 **Q26. Have you provided the data to NIPSCO Witness Linda E. Miller to support her**
8 **adjustment for this expense?**

9 A26. Yes. At my direction and under my supervision, my staff provided this information to
10 Ms. Miller reflected in Petitioner's Exhibit LEM-2.

11 **Q27. What contract labor costs does NIPSCO incur in its generation operations?**

12 A27. NIPSCO contracts with outside companies to provide labor for many generation projects.
13 Manpower requirements peak during unit outages and require outside workers to
14 complete the many O&M projects in a reasonable time frame.

15 **Q28. Why has NIPSCO's contract labor cost increased since the close of the test year?**

16 A28. Competition for skilled workers in Northwest Indiana has increased which has generated
17 challenges in sourcing contract labor. For example, the BP refinery in Whiting, Indiana
18 will be implementing a major expansion over the next several years which will require a
19 contract work force that is expected to peak at approximately 4,000 people. This project
20 will draw from the same skilled labor force that NIPSCO utilizes to do the work in its

1 generating facilities. This heightened competition for skilled labor force results in
2 NIPSCO being unable to engage the most experienced labor, which results in more time
3 and cost to fulfill equivalent work tasks.

4 **Q29. Do you believe the current skilled labor shortage will abate in the near future?**

5 A29. No, I do not. NIPSCO's experience in engaging contract labor is that the cost continues
6 to increase annually. This experience is supported by studies I have reviewed. The
7 Federal Energy Regulatory Commission ("FERC") recently instructed its Staff to
8 investigate the upward pressure on electricity prices. The FERC Staff reported its
9 findings on June 19, 2008. I have attached a copy of that report to my testimony as
10 Petitioner's Exhibit PWP-4 and will refer to this report hereafter as the "FERC Report".
11 The FERC Report (p. 10) shows that the average yearly labor increase in the Electric
12 Industry over the last 8 years is 3.375%. A report from the Brattle Group entitled the
13 Rising Utility Construction Costs (pp. 20-21), which I have also attached to my testimony
14 as Petitioner's Exhibit PWP-5, substantiates this conclusion.

15 **Q30. What level of increased costs are you proposing for the adjustment?**

16 A30. The adjustment I propose is based on the average yearly labor increase in the Electric
17 Industry over the last 8 years noted by the FERC Report and the Rising Utility
18 Construction Costs from the Brattle Group. These studies show annual labor increases of
19 3.375%. Because NIPSCO intends to use, at least, the same amount of contracted O&M
20 labor in 2008 as it did in 2007 (\$29,827,075), I multiplied this annual cost increase by the

1 amount of 2007 contracted O&M labor. This results in a cost increase for contracted
2 labor of \$1,006,664 that should be added to NIPSCO's actual costs for 2007.

3 **IV. AMENDMENTS TO NIPSCO'S ENVIRONMENTAL COST RECOVERY**
4 **MECHANISMS**

5 **Q31. Are you familiar with NIPSCO's environmental compliance cost recovery filings?**

6 A31. Yes. I have previously testified in support of NIPSCO's implementation of the
7 ratemaking treatment for qualified pollution control property ("QPCP"), as authorized by
8 the Commission in its Order entered November 26, 2002, in Cause No. 42150 ("Order")
9 and its Order entered, July 3, 2007, in Cause No. 43188 ("CAIR/CAMR Order"). In
10 addition, I have testified in support of NIPSCO's proposed rate adjustments for recovery
11 of operating, maintenance and depreciation expenses connected with the operation of its
12 QPCP that is in service, as authorized by the Commission in its Order. My testimony has
13 related to NIPSCO's Environmental Cost Recovery Mechanism ("ECRM") and its
14 Environmental Expense Recovery Mechanism ("EERM"), which are applicable to
15 NIPSCO electric utility customers.

16 **Q32. Is NIPSCO proposing any changes in its ECRM or EERM?**

17 A32. Yes. NIPSCO is proposing to clarify that its ECRM and EERM are designed to recover
18 costs associated with compliance with current and anticipated air regulations on a semi-
19 annual basis, including recovery through its EERM of emission allowance purchase costs
20 and the crediting of revenues from the sale of any emission allowances. NIPSCO
21 Witness Frank A. Shambo discusses the regulatory policies driving these changes.

1 **Q33. Does this conclude your prepared direct testimony?**

2 **A33. Yes it does.**

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

PHILIP W. PACK

**DIRECTOR, GENERATION SUPPORT SERVICES AND MAJOR
PROJECTS**

SPONSORING PETITIONER'S EXHIBITS PWP-2 THROUGH PWP-5

VERIFIED DIRECT TESTIMONY OF PHILIP W. PACK

1 **Q1. Please state your name and business address.**

2 A1. My name is Philip W. Pack. My business address is 2755 Raystone Drive, Valparaiso,
3 Indiana, 46383.

4 **Q2. By whom are you employed and in what capacity?**

5 A2. I am employed by Northern Indiana Public Service Company ("NIPSCO" or the
6 "Company") as Director, Generation Support Services and Major Projects. In this role, I
7 am responsible for management of capital and operation and maintenance ("O&M")
8 projects throughout NIPSCO's generation operations.

9 **Q3. What is your educational background?**

10 A3. I received a bachelor degree in Mechanical Engineering from Western Michigan
11 University in 1980, and I am a Licensed Professional Engineer in the State of Indiana.

12 **Q4. Please describe your professional experience.**

13 A4. I began my employment with NIPSCO in 1981 in the Results Department. My
14 experience includes various technical and management positions in Electric Production
15 prior to my promotion to Operations Manager of Bailly Generating Station in 2000,
16 Compliance Projects Manager in March 2002, Manager, Major Projects and Resource
17 Development in June 2006 and Director, Generation Support Services and Major Projects
18 in September 2008.

19

1 **Q5. Have you previously testified before this or any other regulatory commission?**

2 A5. Yes, I have testified before the Indiana Utility Regulatory Commission ("Commission")
3 on environmental matters for NIPSCO in several proceedings including Cause Nos.
4 42150, 43144 and 43371.

5 **Q6. What is the purpose of your testimony?**

6 A6. The purpose of my testimony is to: (1) describe NIPSCO's generation fleet and changes
7 to that fleet, including the retirement and demolition of the D. H. Mitchell Generating
8 Station ("Mitchell") and Michigan City Generating Station ("Michigan City") Units 2
9 and 3; (2) support an operation and maintenance ("O&M") expense adjustment to reflect
10 increases in contract labor costs shown on Petitioner's Exhibit LEM-2; and (3) explain
11 adjustments to NIPSCO's environmental cost recovery mechanisms.

12 **I. NIPSCO'S GENERATION FLEET**

13 **Q7. Are you generally familiar with NIPSCO's generating facilities?**

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15 **Q8. Please generally describe NIPSCO's generation fleet at the end of the test year.**

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17 consist of six (6) separate generation sites, including the Company's R.M. Schahfer
18 Generating Station, Michigan City, Bailly Generating Station, Mitchell and two (2)
19 hydroelectric generating sites near Monticello, Indiana. Of the total capacity, 92.4% is
20 from coal-fired units, 7.3% is from natural gas-fired units and 0.3% is from hydroelectric

1 units. Petitioner's Exhibit PWP-2 provides a summary of the generating facilities
2 operated by NIPSCO.

3 **Q9. Has NIPSCO made any capital investment in generation facilities not included in**
4 **test year results?**

5 A9. Yes. As NIPSCO Witness Bradley K. Sweet explains, on May 30, 2008, NIPSCO
6 acquired Sugar Creek Power Company, LLC which then owned a 535 MW combined
7 cycle gas turbine ("CCGT" or "Sugar Creek") located near Terre Haute, Indiana. Sugar
8 Creek Power Company, LLC was then merged into NIPSCO. As a result of this
9 transaction, NIPSCO now owns the CCGT. Sugar Creek is configured with two
10 combustion gas turbines ("CTs") and one steam turbine generator ("STG"). Sugar Creek
11 has the ability to interconnect with either the Midwest Independent Transmission System
12 Operator, Inc. (the "Midwest ISO") or the PJM Interconnection, LLC ("PJM").

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14 **from the Commission prior to acquiring Sugar Creek?**

15 A10. Yes. The Commission granted NIPSCO a CPCN for the acquisition of Sugar Creek in its
16 May 28, 2008 Order in Cause No. 43396 (the "CPCN Order").

17 **Q11. Which Regional Transmission Organization is Sugar Creek interconnected to now?**

18 A11. As of December 1, 2008, Sugar Creek is a Designated Network Resource in the Midwest
19 ISO.

20 **Q12. Can NIPSCO determine the non-fuel O&M expenses associated with Sugar Creek?**

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2 under NIPSCO ownership. The actual O&M expenses from the last 12 months were
3 \$6,056,289 and were \$2,959,650 for the last 6 months under NIPSCO ownership. I have
4 reviewed this information and believe it to be reliable. The projected non-fuel O&M
5 expense to operate Sugar Creek from December 1, 2008 through November 30, 2009 is
6 \$5,919,299. Attached hereto as Petitioner's Exhibit PWP-3 (Revised) is a breakdown of
7 the O&M expenses for Sugar Creek. This adjustment does not include tax expense
8 associated with Sugar Creek, which is addressed by NIPSCO Witness John O'Brien.

9 **Q13. How did NIPSCO calculate the O&M expenses for Sugar Creek for the twelve**
10 **months commencing December 1, 2008?**

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12 value to obtain the 12 month projection. This method to determine the O&M
13 requirement is considered conservative as the value is less than the last 12 month actual
14 O&M expenses. The variable O&M expenses associated with the Long Term Service
15 Agreement ("LTSA") are included in the O&M expenses projection. NIPSCO did not
16 include fixed O&M expenses associated with the LTSA overhaul costs as the overhauls
17 will not occur for several years.

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20 maintenance on the Sugar Creek facility turbines and generators. The LTSA was
21 executed prior to NIPSCO's acquisition of the Sugar Creek facility and NIPSCO assumed

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2 by the number of operating starts and hours. NIPSCO's due diligence of the Sugar Creek
3 facility compared the confidential prices of the LTSA to market prices and determined
4 the LTSA has favorable economic terms.

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8 7 experienced a planned outage to combine maintenance with the installation of
9 environmental control equipment. The Unit was scheduled for the replacement of the
10 boiler cyclones, various boiler pressure parts, a turbine overhaul and the installation of a
11 Selective Catalytic Reduction ("SCR") system for NOx reduction. Due to the amount of
12 work that was scheduled, two outages totaling 25 weeks were required to prevent
13 interference among projects. Installation of an SCR at Unit 7 is a one time event that is
14 not anticipated to occur again. Unit 10 experienced a forced outage on February 1, 2007.
15 This outage was caused by a failure of the rotor stub shaft bolting resulting in extensive
16 turbine damage. This outage lasted through the end of 2007 and into 2008 due to
17 difficulties obtaining replacement components. Unit 16A also experienced a long forced
18 outage beginning August 1, 2007. The outage was caused by a failure of blade locking
19 pins that caused extensive damage to the compressor section of the unit. Damage of this
20 kind is not typical and would not be something I would expect to occur in the future. The
21 outage continued throughout the end of the 2007 year and into 2008. Due to these

unusual constraints, the 2007 operational availability for Units 7, 10 and 16A should be adjusted as described in Mr. Sweet's testimony.

II. DEMOLITION OF CERTAIN UNITS

Q16. What generation facilities is NIPSCO retiring?

A16. NIPSCO is retiring Mitchell and Michigan City Units 2 and 3.

Q17. Please describe Mitchell.

A17. Mitchell has four coal fired units which range in age from 38 to 52 years old. At shutdown in 2002, Units 5, 6, and 11 burned low sulfur sub-bituminous coal from the Powder River Basin in Wyoming. Unit 4 had the capability to burn either natural gas or Powder River Basin coal. The net capacity of the four coal fired units totaled 485 MW. As indicated in Mr. Sweet's testimony, Units 4, 5, 6 and 11 were indefinitely shutdown in January 2002. Unit 9 is a natural gas combustion turbine capable of 17 MW of output.

Q18. Why is NIPSCO retiring Mitchell?

A18. Mr. Sweet describes in more detail the reasons NIPSCO no longer intends to operate Mitchell. The restart of the shutdown Mitchell units was considered in NIPSCO's 2007 Integrated Resource Plan ("IRP") modeling as a supply-side option. The IRP suggested the Mitchell restart options should be abandoned in lieu of purchasing one or more CCGTs because of the \$587,500,000 cost to restart Mitchell. As indicated in Table 7-8 (page 145) of the 2007 NIPSCO IRP, the New Energy "Strategist" Model never selected a Mitchell reactivation option as a low-cost supply-side resource in the next 20 years.

1 NIPSCO will retire Mitchell, demolish the facilities and remediate the site to industrial
2 condition.

3 **Q19. What is generally involved in demolishing and remediating Mitchell?**

4 A19. As described in the demolition cost study prepared by Burns & McDonnell and submitted
5 as Petitioner's Exhibit VFR-3, Mitchell's demolition will include removal of equipment
6 at the site, as well as any building structures, but leaving the below grade piping and
7 wiring in place. Foundations will be filled to grade and the coal pile and ash ponds will
8 be covered with soil and seeded. Burns & McDonnell estimates that remediating
9 Mitchell will take approximately 30 months.

10 **Q20. Please describe the Michigan City Units 2 and 3?**

11 A20. The two natural gas fired units at Michigan City station range in age from to 57 to 58
12 years old. The net capacity of the units totaled 120 MW. The boilers for Units 2 and 3
13 were coal-fired until 1988 when the operation was limited to natural gas only to reduce
14 SO₂ emissions from the plant. As indicated by Mr. Sweet, Michigan City Unit 2 and 3
15 were indefinitely shutdown in June 2005 due to the condition of the boilers.

16 **Q21. Why is NIPSCO retiring the Michigan City Units 2 and 3?**

17 A21. Mr. Sweet explains why NIPSCO is retiring Michigan City Units 2 and 3. In general
18 terms, NIPSCO has determined the units are at the end of their useful life due to
19 extensive tube corrosion damage to boiler walls and cyclones. Additionally, the turbines
20 and auxiliary systems have extensive wear due to their 50 plus years of service. NIPSCO

1 will retire Units 2 and 3 and demolish the facilities in the manner described in the Burns
2 & McDonnell demolition studies marked as Petitioner's Exhibit VFR-6.

3 **Q22. What is generally involved in demolishing the Michigan City Units 2 and 3?**

4 A22. As described in the Burns & McDonnell demolition study, the demolition of Units 2 and
5 3 includes removal of all associated equipment, piping, wiring and HVAC equipment not
6 necessary for continued operations of Michigan City Unit 12. The shell of the building
7 would remain in-place. Burns & McDonnell estimates demolishing Michigan City Units
8 2 and 3 will take approximately 22 months.

9 **Q23. Will any Michigan City units remain in service after the retirement of Units 2 and**
10 **3?**

11 A23. Yes. Michigan City Unit 12 will remain a supply-side resource for NIPSCO and will
12 remain in service.

13 **Q24. Are you familiar with the information relied upon by Burns & McDonnell in the**
14 **preparation of the demolition studies and sponsored by Mr. Ranaletta?**

15 A24. Yes, I am. The Burns & McDonnell demolition cost studies sponsored by Mr.
16 Ranaletta's testimony rely on NIPSCO site and equipment drawings, historic
17 contamination associated with Solid Waste Management Units and asbestos remediation
18 estimates prepared by NIPSCO's asbestos contractor Insulco. Based upon my knowledge
19 and review of these documents, this information can be relied upon by Burns &
20 McDonnell in the preparation of its demolition cost studies.

III. GENERATION O&M EXPENSE ADJUSTMENT

Q25. Are you supporting any adjustments to O&M for generation?

A25. Yes. I recommend an upward adjustment to O&M generation maintenance expense to reflect increases in contract labor costs.

Q26. Have you provided the data to NIPSCO Witness Linda E. Miller to support her adjustment for this expense?

A26. Yes. At my direction and under my supervision, my staff provided this information to Ms. Miller reflected in Petitioner's Exhibit LEM-2.

Q27. What contract labor costs does NIPSCO incur in its generation operations?

A27. NIPSCO contracts with outside companies to provide labor for many generation projects. Manpower requirements peak during unit outages and require outside workers to complete the many O&M projects in a reasonable time frame.

Q28. Why has NIPSCO's contract labor cost increased since the close of the test year?

A28. Competition for skilled workers in Northwest Indiana has increased which has generated challenges in sourcing contract labor. For example, the BP refinery in Whiting, Indiana will be implementing a major expansion over the next several years which will require a contract work force that is expected to peak at approximately 4,000 people. This project will draw from the same skilled labor force that NIPSCO utilizes to do the work in its generating facilities. This heightened competition for skilled labor force results in NIPSCO being unable to engage the most experienced labor, which results in more time and cost to fulfill equivalent work tasks.

1 **Q29. Do you believe the current skilled labor shortage will abate in the near future?**

2 A29. No, I do not. NIPSCO's experience in engaging contract labor is that the cost continues
3 to increase annually. This experience is supported by studies I have reviewed. The
4 Federal Energy Regulatory Commission ("FERC") recently instructed its Staff to
5 investigate the upward pressure on electricity prices. The FERC Staff reported its
6 findings on June 19, 2008. I have attached a copy of that report to my testimony as
7 Petitioner's Exhibit PWP-4 and will refer to this report hereafter as the "FERC Report".
8 The FERC Report (p. 10) shows that the average yearly labor increase in the Electric
9 Industry over the last 8 years is 3.375%. A report from the Brattle Group entitled the
10 Rising Utility Construction Costs (pp. 20-21), which I have also attached to my testimony
11 as Petitioner's Exhibit PWP-5, substantiates this conclusion.

12 **Q30. What level of increased costs are you proposing for the adjustment?**

13 A30. The adjustment I propose is based on the average yearly labor increase in the Electric
14 Industry over the last 8 years noted by the FERC Report and the Rising Utility
15 Construction Costs from the Brattle Group. These studies show annual labor increases of
16 3.375%. Because NIPSCO intends to use, at least, the same amount of contracted O&M
17 labor in 2008 as it did in 2007 (\$29,827,075), I multiplied this annual cost increase by the
18 amount of 2007 contracted O&M labor. This results in a cost increase for contracted
19 labor of \$1,006,664 that should be added to NIPSCO's actual costs for 2007.

20 **IV. AMENDMENTS TO NIPSCO'S ENVIRONMENTAL COST RECOVERY**
21 **MECHANISMS**

1 **Q31. Are you familiar with NIPSCO's environmental compliance cost recovery filings?**

2 A31. Yes. I have previously testified in support of NIPSCO's implementation of the
3 ratemaking treatment for qualified pollution control property ("QPCP"), as authorized by
4 the Commission in its Order entered November 26, 2002, in Cause No. 42150 ("Order")
5 and its Order entered, July 3, 2007, in Cause No. 43188 ("CAIR/CAMR Order"). In
6 addition, I have testified in support of NIPSCO's proposed rate adjustments for recovery
7 of operating, maintenance and depreciation expenses connected with the operation of its
8 QPCP that is in service, as authorized by the Commission in its Order. My testimony has
9 related to NIPSCO's Environmental Cost Recovery Mechanism ("ECRM") and its
10 Environmental Expense Recovery Mechanism ("EERM"), which are applicable to
11 NIPSCO electric utility customers.

12 **Q32. Is NIPSCO proposing any changes in its ECRM or EERM?**

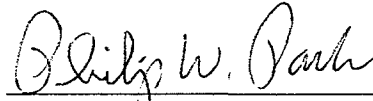
13 A32. Yes. NIPSCO is proposing to clarify that its ECRM and EERM are designed to recover
14 costs associated with compliance with current and anticipated air regulations on a semi-
15 annual basis, including recovery through its EERM of emission allowance purchase costs
16 and the crediting of revenues from the sale of any emission allowances. NIPSCO
17 Witness Frank A. Shambo discusses the regulatory policies driving these changes.

18 **Q33. Does this conclude your prepared direct testimony?**

19 A33. Yes it does.

VERIFICATION

I, Philip W. Pack, Manager, Major Projects & Resource Development for NIPSCO,
affirm under penalties of perjury that the foregoing representations are true and correct to the
best of my knowledge, information and belief.

A handwritten signature in cursive script, reading "Philip W. Pack", written over a horizontal line.

Philip W. Pack

Date: December 19, 2008

Sugar Creek Projected Operating Expenses for December 2008 thru November 2009
(all numbers in dollars)

	Fixed Costs	Variable Costs
Maintenance Parts & Service	392,024	447,069
Long Term Service Agreement (G.E.)	0	1,274,300
Chemicals	0	148,983
Consumables	149,575	
Utilities	5,946	
Site Labor	2,412,315	
Employee and Community Relations	11,782	
Training and Travel	33,036	
Office Expenses	88,240	
Communications	52,412	
Vehicles	14,086	
Buildings and Grounds	115,930	
Subcontractor Services	75,321	
Insurance	343,480	
Professional Services	289,200	
Administrative	65,600	
Permits and Emission Fees	0	
 Fixed & Variable Expenses	 4,048,946	 1,870,352
 Total Expenses		 5,919,299

Based on June 1, 2008 through November 30, 2008 actual expenses

1 Director, Regulatory and Government Policy in January 2004. I assumed my current
2 position of Vice President, Regulatory and Legislative Affairs on April 1, 2008.

3 **Q4. Have you previously testified before this or any other regulatory commission?**

4 A4. Yes, I have previously testified before the Indiana Utility Regulatory Commission
5 ("Commission") on behalf of NIPSCO in Cause No. 43186, involving NIPSCO's
6 purchased power benchmark; Cause No. 43396, involving NIPSCO's acquisition of the
7 Sugar Creek Generating Facility ("Sugar Creek Facility" or "Facility"); and various fuel
8 adjustment clause ("FAC") proceedings.

9 **Q5. What is the purpose of your direct testimony in this proceeding?**

10 A5. The purpose of my direct testimony is to: (1) provide a brief background of NIPSCO's
11 existing rates; (2) explain certain proforma adjustments made to test year operating
12 results; (3) provide an overview of the principles NIPSCO used in developing the rates
13 proposed in this proceeding; (4) explain key rules used in the development of rates and
14 how those rules align with the established principles; ~~(5) review NIPSCO's Step Two rate~~
15 ~~increase proposal associated with the Sugar Creek Facility;~~ (6) illustrate the rationale for
16 NIPSCO's proposed Reliability Adjustment ("RA") tracking mechanism; ~~(7)~~ briefly
17 discuss NIPSCO's effort to simplify its tariff structure; and ~~(8)~~ discuss NIPSCO's future
18 steps related to rate offerings.

1 Environmental Expense Recovery Mechanism ("EERM") and Environmental Cost
2 Recovery Mechanism ("ECRM").

3 **Q9. Please describe the scope of the tariff revisions proposed by NIPSCO in this**
4 **proceeding.**

5 A9. As discussed in more detail by NIPSCO Witnesses Curt A. Westerhausen and Robert D.
6 Greneman, rather than making minor revisions to the current tariff, which has evolved in
7 a piecemeal fashion over the past two decades, NIPSCO chose to substantially revise its
8 tariff reflecting a complete assessment of ratemaking principles, cost of service and bill
9 impacts.

10 **III. REVENUE ADJUSTMENTS TO TEST YEAR**

11 **Q10. Have you reviewed the testimony of NIPSCO Witness Linda E. Miller?**

12 A10. Yes. I will discuss the following five adjustments to test year revenues reflected in
13 Petitioner's Exhibit LEM-2 (Revised) sponsored by Ms. Miller: (1) an increase in
14 NIPSCO's test year revenue to reflect the fact that certain large industrial customers were
15 receiving discounts from tariff rates under special contracts during the test year; (2) a
16 reduction in NIPSCO's test year revenue for certain customers that had consumption
17 greater than the level that will be available to them in the future; (3) a reduction in
18 NIPSCO's test year revenue to eliminate off-system sales margins; (4) a reduction in
19 NIPSCO's test year revenue to eliminate the net proceeds from the sale of emissions

1 A39. Upon completion of the class embedded cost study, it was apparent that a substantial cost
2 shift was occurring among the three major customer classes. Because existing rates date
3 back to the early 1980's, there are many possible explanations for the changes, including
4 fundamental shifts in demand in the commercial class that has moved from smaller units
5 to big box operations during this period, and changing residential usage patterns with the
6 major changes in electrical appliances over this period. NIPSCO suspects, but cannot
7 confirm, that the current tariff reflects some social engineering of the rates to shift costs
8 from residential to commercial and industrial customers. Whatever the reason, NIPSCO
9 seeks to move toward rates that rely on cost-based allocations with limited social
10 adjustments. However, moving to cost-based allocations in one step (after 20 years)
11 would result in a ~~23.23~~21.4% increase in basic rates for residential customers.

12 NIPSCO is therefore proposing that a 25 percent decrease in the existing subsidy ~~only one-~~
13 ~~third of the full cost-based rate increase to the residential Rate be implemented in this~~
14 proceeding, yielding an average 16.73~~7.74~~% increase in basic rates to residential
15 customers.

16 **Q40. Are you familiar with NIPSCO's load research study?**

17 A40. Yes, I am. To improve the allocation of demand costs, NIPSCO conducted additional
18 load research on our customer segments that have lower usage levels, specifically small
19 commercial and residential customers. It should be noted that NIPSCO has detailed
20 meter information (hourly or at least periodic demand) on over 50% of our annual volume

1 revenues as jurisdictional for purposes of NIPSCO's calculation of compliance with the
2 earnings test in its FAC.

3 **~~VI. TWO STEP RATE ADJUSTMENT PROPOSAL~~**

4 **~~Q43. Please explain NIPSCO's proposal to implement its proposed rate adjustments in~~**
5 **~~two steps.~~**

6 ~~A43. NIPSCO is proposing to adjust its rates and charges in two steps. The first step ("Step~~
7 ~~One") would adjust NIPSCO's rates to reflect rate base in service as of December 31,~~
8 ~~2007 and the financial results using the 2007 test year adjusted for fixed, known and~~
9 ~~measurable changes. Step One would be effective immediately upon the issuance of the~~
10 ~~Commission Order in this proceeding approving new base rates. The second step ("Step~~
11 ~~Two") would reflect capital costs and operating expenses relating to the Sugar Creek~~
12 ~~Facility. Step Two would be implemented when the Sugar Creek Facility becomes~~
13 ~~dispatchable in the Midwest ISO.~~

14 **~~Q44. Please describe the Sugar Creek Facility.~~**

15 ~~A44. The Sugar Creek Facility is a 535 MW combined cycle combustion turbine generating~~
16 ~~facility ("CCGT") located near Terre Haute, Indiana. The Sugar Creek Facility was~~
17 ~~acquired by NIPSCO through the purchase of the equity interests in Sugar Creek Power~~
18 ~~Company, LLC and the subsequent merger of that company into NIPSCO. NIPSCO~~
19 ~~acquired the equity interests on May 30, 2008 pursuant to the Commission's Order in~~
20 ~~Cause No. 43396 dated May 28, 2008 ("CPCN Order") granting NIPSCO a Certificate of~~

Public Convenience and Necessity ("CPCN") for the acquisition and NIPSCO assumed control of the Sugar Creek Facility on that date. The Sugar Creek Facility is capable of connection to either the Midwest ISO or the PJM Interconnection, LLC ("PJM") markets.

Q45. Why is NIPSCO proposing Step Two to reflect the capital costs and operating expenses relating to the Sugar Creek Facility?

A45. NIPSCO's Step Two rate adjustment is necessary to resolve a difference between the time when the Sugar Creek Facility can be reflected in NIPSCO's retail rates and the time NIPSCO agreed to initiate this rate proceeding. NIPSCO committed to initiate this rate proceeding by July 1, 2008 in a settlement approved by the Commission's Order dated August 23, 2006 in Cause No. 42824. NIPSCO was not able to acquire control of the Sugar Creek Facility until May 30, 2008. Because the Sugar Creek Facility is committed to the PJM market through May 31, 2010, NIPSCO proposed in Cause No. 43396 a mechanism to pass revenues earned from PJM to retail customers which it believed would render the Sugar Creek Facility sufficiently used and useful to be included in NIPSCO's rate base while committed to PJM. In the CPCN Order, however, the Commission determined that the Sugar Creek Facility would not be deemed "in-service" or "used and useful" to NIPSCO's ratepayers until the Facility is dispatched into the Midwest ISO. Notwithstanding the CPCN Order, NIPSCO did finalize the purchase of the Facility following the issuance of the CPCN Order because it believed acquisition of the Facility was in the best interest of its customers. NIPSCO is proposing the Step Two rate adjustment in this proceeding to incorporate the costs associated with the Sugar

1 Creek Facility once it becomes used and useful as prescribed in the CPCN Order. The
2 CPCN Order provided that a review of "the inclusion of costs of the purchase of the
3 Sugar Creek Facility in NIPSCO's forthcoming rate case . . . (to the extent requested) can
4 occur as part of that proceeding" CPCN Order, p. 32.

5 **~~Q46. Why did NIPSCO acquire a generation facility that was committed to PJM through~~**
6 **~~May 31, 2010?~~**

7 ~~A46. NIPSCO initiated two requests for proposals ("RFP") to identify potential sources to meet~~
8 ~~its generation needs. The first RFP required potential CCGT's be capable of dispatch~~
9 ~~into the Midwest ISO after January 1, 2009 and a second RFP solicited further CCGT's~~
10 ~~capable of dispatch into the Midwest ISO by May 31, 2008. Proposals for the Sugar~~
11 ~~Creek Facility were received in response to both RFPs. Only after NIPSCO commenced~~
12 ~~its evaluation did it learn through its due diligence process that the Sugar Creek Facility,~~
13 ~~although physically capable of dispatching load into the Midwest ISO, was committed to~~
14 ~~the PJM market through May 31, 2010.~~

15 **~~Q47. Why did NIPSCO continue evaluating the Sugar Creek Facility as a potential~~**
16 **~~generation option?~~**

17 ~~A47. Notwithstanding the Facility's commitment to PJM, acquisition of the Sugar Creek~~
18 ~~Facility continued to rank highly in NIPSCO's evaluation of its alternatives. NIPSCO~~
19 ~~concluded it was inappropriate to exclude from consideration a plant that will provide~~
20 ~~many decades of service to its customers and offered such favorable economic terms~~

1 because of a two year commitment to PJM. Investigation of the Sugar Creek Facility
2 continued and NIPSCO eventually executed a purchase agreement for the Facility. In its
3 CPCN Order, the Commission concluded the public convenience and necessity required
4 NIPSCO's acquisition of the Sugar Creek Facility and granted NIPSCO a CPCN to
5 acquire the Sugar Creek Facility. The Commission expressly found that "NIPSCO's
6 purchase of [Sugar Creek] will, in 2010, add needed capacity for the benefit of its
7 ratepayers." CPCN Order at 26 (emphasis added).

8 ~~Q48. Will NIPSCO evaluate withdrawing the Sugar Creek Facility from the PJM~~
9 ~~commitment?~~

10 ~~A48. Yes. NIPSCO will explore any opportunities that may arise to terminate the PJM~~
11 ~~commitment earlier than May 31, 2010. However, there are contractual and regulatory~~
12 ~~obstacles to such a change. NIPSCO will pursue reasonable options to dispatch the Sugar~~
13 ~~Creek Facility into the Midwest ISO as soon as possible, but there is no assurance that~~
14 ~~this can be accomplished earlier than June 1, 2010.~~

15 ~~Q49. How does NIPSCO propose to deal with carrying costs and depreciation expense~~
16 ~~relating to the Sugar Creek Facility?~~

17 ~~A49. NIPSCO proposes to include deferred depreciation expense and carrying costs relating to~~
18 ~~its investment in the Sugar Creek Facility in Step Two pursuant to the relief NIPSCO~~
19 ~~seeks in Cause No. 43396-S1. In that subdocket, NIPSCO proposes an alternative~~
20 ~~regulatory plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6 for this treatment. NIPSCO is~~

1 proposing to recover the deferred depreciation and carrying costs commencing with the
2 proposed Step Two rate increase. NIPSCO proposes to recover these deferrals over a five
3 year period, after which NIPSCO's rates will be adjusted to remove the recovery of the
4 deferrals. This proposal is consistent with the FAC71-S1 Settlement.

5 **Q50. How does NIPSCO propose to calculate its Step Two rates?**

6 A50. Ms. Miller has calculated the revenue requirement for Step Two. Mr. Greneman then
7 used the same cost allocation method as used in Step One and the same billing
8 determinants in section two of his cost of service study. NIPSCO is not proposing any
9 revision to the fully allocated cost methodology described Mr. Greneman. Petitioner's
10 Exhibit CAW-3 contains the proposed rates for Step Two. In Step Two, NIPSCO is
11 proposing approximately an \$80 million increase in basic rates, yielding an average
12 9.05% rate increase in basic rates.

13 **Q51. What procedures does NIPSCO propose in order to implement the Step Two rate**
14 **adjustment?**

15 A51. NIPSCO proposes to implement the Step Two rate adjustment as soon as the Sugar Creek
16 Facility is dispatched into the Midwest ISO market. The latest this will occur is June 1,
17 2010. Ms. Miller has calculated the Step Two rate adjustment based on the revenue
18 requirement relating to the Sugar Creek Facility. NIPSCO will file a written verification
19 with the Commission when the Facility is dispatchable into the Midwest ISO. NIPSCO
20 requests that the Commission authorize NIPSCO to place the Step Two rates in effect

1 immediately upon the submission of the verification. If the Sugar Creek Facility will be
2 dispatched to the Midwest ISO prior to June 1, 2010, NIPSCO will adjust Ms. Miller's
3 rate calculation for the shorter period over which the amortized costs would be deferred
4 and file a revised tariff reflecting that change. A subsequent tariff filing will be made to
5 remove the portion of the rates recovering the amortized depreciation and carrying costs
6 after those costs have been fully recovered to comport with the terms of the FAC71-S1
7 Settlement.

8 **Q52. Are you aware of any prior Commission orders approving a rate adjustment similar**
9 **to the Step Two proposal?**

10 A52. Yes, I am. In its December 3, 1984 Order in Cause No. 37457, the Commission
11 authorized Indiana & Michigan Electric Company ("I&M") to implement a second step
12 rate increase twelve months after the first rate increase went into effect for its Rockport
13 generating station. In its August 24, 1995 Order in Cause No. 39938, the Commission
14 approved a settlement agreement providing for a two phase rate increase for Indianapolis
15 Power & Light Company where the second phase was to go into effect nine months after
16 the first phase to reflect the in-service date of certain environmental control property. In
17 its December 2, 1992 Order in Cause No. 39381, the Commission authorized
18 Crawfordsville Electric Light & Power to implement a two phase rate increase with the
19 second phase going into effect upon placing in service new electric plant. All of these
20 orders were approved under traditional ratemaking principles.

1 Q53. Is NIPSCO's proposal for a Step Two rate increase in the public interest?

2 VI. ~~YES. AS RECOGNIZED BY THE GRANT OF A CPCN THROUGH THE CPCN~~
3 ~~ORDER, THE PUBLIC CONVENIENCE AND NECESSITY WERE SERVED BY~~
4 ~~NIPSCO'S PURCHASE OF THE SUGAR CREEK FACILITY. THE FACILITY'S~~
5 ~~PURCHASE BROUGHT NECESSARY CAPACITY AND FUEL DIVERSITY TO~~
6 ~~NIPSCO'S GENERATING MIX. NIPSCO'S 2007 INTEGRATED RESOURCE~~
7 ~~PLAN DEMONSTRATED THAT NIPSCO WOULD NEED TO EITHER~~
8 ~~ACQUIRE OR CONSTRUCT ADDITIONAL GENERATION FACILITIES AS~~
9 ~~PART OF ITS STRATEGY TO MEET ITS CAPACITY REQUIREMENTS.~~
10 ~~ACQUISITION OF THE SUGAR CREEK FACILITY RESULTED FROM~~
11 ~~NIPSCO'S THOROUGH RFP PROCESS DESIGNED TO IDENTIFY THE MOST~~
12 ~~COST EFFECTIVE OPTIONS TO MEET ITS NEED FOR ADDITIONAL~~
13 ~~GENERATION. THE SUGAR CREEK FACILITY WAS THE MOST COST~~
14 ~~EFFECTIVE ALTERNATIVE FOR NIPSCO TO ACQUIRE NEEDED~~
15 ~~CAPACITY. HAD NIPSCO CONSTRUCTED AN EQUIVALENT FACILITY,~~
16 ~~THE COST TO RATEPAYERS WOULD HAVE BEEN TWO TO SIX TIMES~~
17 ~~WHAT IT IS WITH THE SUGAR CREEK FACILITY AND NIPSCO WOULD~~
18 ~~HAVE BEEN ABLE TO CAPITALIZE CARRYING COSTS ON ITS~~
19 ~~INVESTMENT DURING THE CONSTRUCTION PERIOD THROUGH~~
20 ~~ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION. PENALIZING~~
21 ~~NIPSCO FOR ACQUIRING THE LOWEST COST FACILITY BECAUSE OF ITS~~

~~TEMPORARY COMMITMENT TO ANOTHER REGIONAL TRANSMISSION
ORGANIZATION WOULD DISCOURAGE INDIANA UTILITIES FROM
EXPLORING SUCH OPPORTUNITIES. THIS COULD RESULT IN HIGHER
PRICES FOR INDIANA RETAIL CUSTOMERS.~~ THE RA MECHANISM

A53.

~~VII. THE RA MECHANISM~~

Q54.Q43. What costs and offsetting revenues is NIPSCO seeking to recover through the proposed RA mechanism?

A54.A43. NIPSCO is seeking recovery of all purchased power costs, capacity costs, and all non-FAC MISO costs offset by non-FAC MISO credits and off-system sales margins as detailed by Mr. Crum.

Q55.Q44. Please describe why NIPSCO is seeking to recover these costs through the RA.

A55.A44. As Mr. Crum describes, these costs are necessary components to the provision of reliable service. NIPSCO believes that because of the variable nature of these costs, recovery through a tracker is more appropriate than including it as an operating expense when establishing NIPSCO's fair rate of return. These costs will be reviewable on a quarterly basis in the RA mechanism. Including these costs in a tracker assures that NIPSCO will recover no more and no less than the actual costs incurred in connection with these reliability requirements, provides ongoing scrutiny of these costs by the

Commission and provides a means to pass through offsetting revenues and credits to retail customers. For example, capacity costs will be greatly reduced when because the Sugar Creek Facility dispatches into the Midwest ISO. Recovering these costs in the RA ensures that customers receive the benefits of decreases in any of the costs or increases in the credits described above. It also provides more accurate price signals to our customers. I would also note that inclusion of purchased power costs in the RA is consistent with the FAC71-S1 Settlement Agreement, which provided for recovery of these costs through a Section 42(a) mechanism.

NIPSCO proposes to offset these costs by passing back off-system sales margins, as described above, through this mechanism. Many off-system sales are now made the same way energy is purchased – through the Midwest ISO. Accordingly, it is appropriate to use the RA mechanism to pass these margins back to customers.

VII.VII. SIMPLIFICATION OF AND REDUCTION IN THE NUMBER OF RATE SCHEDULES

Q56.Q45. Please provide an overview of NIPSCO's efforts to simplify and reduce its number of rate schedules.

A56.A45. Currently, NIPSCO has 42 Rate Schedules and is proposing a reduction to 13 rate schedules in this proceeding. NIPSCO continues to provide rate flexibility. For example, Rate 534 (customers over 10 MW) is primarily targeted for transmission level customers but the rate design is set based upon delivery at the primary distribution system. Credit is

1 provided to customers who take service at the transmission level in Rate 534. This rate
2 design allows all customers with load over 10 MW to qualify for the service, not just
3 those on the transmission system. NIPSCO is also seeking to simplify its tariff structure
4 by moving elements of the rate schedules that are common into the general rules and
5 regulations, thereby limiting the rate schedules to the service criteria and pricing. Mr.
6 Westerhausen provides a broader discussion of NIPSCO's rate schedules, riders and
7 rules.

8 | **Q57.Q46. Please describe the reclassification process used in defining the tariff**
9 | **categories.**

10 | **A57.A46.** Most residential customers will map easily from Rate 811 to the new Rate 511
11 | schedules. NIPSCO is converting two additional residential rates into riders for Rate 511.
12 | There are a number of schedules in the commercial/small industrial classes that will be
13 | collapsed into just three (3) rate schedules (Rates 521, 523 and 533). Rate 521 is
14 | designed for small commercial customers that do not have demand meters. These
15 | customers are not likely to have as much energy acquisition sophistication as larger
16 | customers. The rate structure is similar to the residential rates with a customer charge
17 | and a volumetric per kWh charge.

18 | Rate 523 contains a broad grouping of customers, estimated at 11,500, that receive power
19 | from the distribution system. This is the first rate schedule that provides a demand
20 | charge. Customers were mapped into this rate schedule from Rates 821, 823 and 824

1 based upon a combination of the assets used to serve these customers, demand data from
2 those customers with permanent demand meters and sampling demand meters. This is a
3 difficult grouping because of the variety of loads within this class. In recognition of this
4 difficulty, NIPSCO is planning to expand the use of IDR meters within this group.
5 NIPSCO is also providing a number of riders that can be used to better fit customer needs
6 in this Rate.

7 Rate 533 contains a smaller group of customers, estimated at 900 plus, that take service at
8 the distribution and transmission levels. These customers, by and large, have had demand
9 meters for some time. Customers were mapped into this rate schedule from 817, 820,
10 821, 823, 824, 826, 832 and 833 based upon a combination of the assets used to serve
11 these customers and demand data from the existing demand meters. NIPSCO will be
12 replacing existing Demand Indicating meters with IDR meters, in this group for better
13 understanding of load characteristics.

14 | **Q58:Q47. Several of the rate schedules require a separate contract with the customer.**

15 | **Is NIPSCO proposing to negotiate a contract unique to each customer?**

16 | **A58:A47.** No. While certain terms in the contracts will be unique to the customer, NIPSCO
17 | will develop standard forms consistent with the tariff. Individual contracts are necessary
18 | to identify customer specific data such as usage history.

19 | **Q59:Q48. Please explain Rider 575?**

1 | A59:A48. NIPSCO's current tariff includes three (3) separate space heating rates.

2 | Consistent with NIPSCO's effort to simplify its tariff, the three (3) existing rate schedules
3 | have been transitioned to one rider, Rider 575. This rider increases the threshold for the
4 | discount applicable to the Energy Charge for residential customers to 700 kWh during
5 | October through April based upon a review of space heating customer usage.

6 | **IX.VIII. DSM PROGRAMS**

7 | **Q60:Q49. Is NIPSCO proposing specific DSM programs in this proceeding?**

8 | A60:A49. No. After consideration of the complexity of filing its first base rate case in over
9 | 20 years, NIPSCO decided that its DSM programs and related concepts should be filed in
10 | a separate proceeding. NIPSCO anticipates making this filing in fall 2008, with the hope
11 | that approval is received by early 2009 in order to allow for specific programs to be
12 | available to customers for the summer of 2009. Given the schedule for this proceeding,
13 | an implementation date that early would not be possible if the DSM programs were
14 | proposed in the context of this proceeding.

15 | **Q61:Q50. Is NIPSCO introducing concepts within this proceeding that are consistent**
16 | **with its DSM efforts?**

17 | A61:A50. Yes. As discussed above, NIPSCO is proposing a number of rate changes to be
18 | more consistent with its efforts to expand DSM. Specifically, NIPSCO is removing
19 | declining blocks, offering an interruptible rate (Rate 536), offering variations of off-peak
20 | rates (Rates 526 and 527) and setting billing determinants for Rates 533 and 534 at 90%

1 of summer peak hours versus 80% of all other hours. Also, as discussed above and by
2 Mr. Dehring, NIPSCO will be introducing IDR meters to a much larger group of
3 customers in an effort to better understand their usage characteristics.

4 | Q62:Q51. Does this conclude your prepared direct testimony?

5 | A62:A51. Yes, it does.

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

FRANK A. SHAMBO

VICE PRESIDENT, REGULATORY AND LEGISLATIVE AFFAIRS

VERIFIED DIRECT TESTIMONY OF FRANK A. SHAMBO

I. INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Frank A. Shambo. My business address is 101 W. Ohio Street, Indianapolis, Indiana 46204.

Q2. What is your role with Northern Indiana Public Service Company ("NIPSCO")?

A2. I am Vice President, Regulatory and Legislative Affairs for NIPSCO.

Q3. Please briefly describe your educational and business experience.

A3. I graduated from Western Illinois University with a Bachelor of Science Degree in Accounting. I also have a Masters of Management Degree in economics and finance from the J.L. Kellogg Graduate School of Management, Northwestern University. During the period 1980 through 1996, I was employed by MidCon, an Occidental Petroleum Company, in various capacities. During the period 1987 through 1996, I was employed in the Marketing Department of Natural Gas Pipeline Company of America ultimately obtaining the position of Director of Marketing for Utility Sales. In 1996, I was a co-founder of mc2, a start-up company and an early entrant into the unregulated retail energy market and served as the Director of Marketing/Finance through 1998 when the company was sold. In 1998 through 2000, I served as Vice President, Finance and Business Development for enable LLC, which was also a start-up company working in concert with utilities across the country on new products and marketing efforts. Beginning in 2000, I served as a consultant for various utilities until my employment by NIPSCO as

1 Director, Regulatory and Government Policy in January 2004. I assumed my current
2 position of Vice President, Regulatory and Legislative Affairs on April 1, 2008.

3 **Q4. Have you previously testified before this or any other regulatory commission?**

4 A4. Yes, I have previously testified before the Indiana Utility Regulatory Commission
5 ("Commission") on behalf of NIPSCO in Cause No. 43186, involving NIPSCO's
6 purchased power benchmark; Cause No. 43396, involving NIPSCO's acquisition of the
7 Sugar Creek Generating Facility ("Sugar Creek Facility" or "Facility"); and various fuel
8 adjustment clause ("FAC") proceedings.

9 **Q5. What is the purpose of your direct testimony in this proceeding?**

10 A5. The purpose of my direct testimony is to: (1) provide a brief background of NIPSCO's
11 existing rates; (2) explain certain proforma adjustments made to test year operating
12 results; (3) provide an overview of the principles NIPSCO used in developing the rates
13 proposed in this proceeding; (4) explain key rules used in the development of rates and
14 how those rules align with the established principles; (5) illustrate the rationale for
15 NIPSCO's proposed Reliability Adjustment ("RA") tracking mechanism; (6) briefly
16 discuss NIPSCO's effort to simplify its tariff structure; and (7) discuss NIPSCO's future
17 steps related to rate offerings.

1 **II. CURRENT RATE STRUCTURE**

2 **Q6. When were NIPSCO's basic rates and charges last established?**

3 A6. NIPSCO's current basic rates and charges were approved by the Commission in its Order
4 dated July 15, 1987 in Cause No. 38045. The Order granted an increase in NIPSCO's
5 basic rates, which was implemented in an across-the-board fashion. Implementation of
6 the rate increase in such a manner was affirmed on reconsideration in the Commission's
7 Order dated March 9, 1988 in Cause No. 38045.

8 **Q7. Did the Commission subsequently investigate NIPSCO's basic rates and charges?**

9 A7. Yes, however, the basic rates and charges established in Cause No. 38045 remain in
10 effect today consistent with the terms of the Settlement Agreement approved by the
11 Commission in its Order dated September 23, 2002 in Cause No. 41746, *affirmed on*
12 *appeal, Citizens Action Coalition of Ind., Inc. v. Northern Ind. Pub. Serv. Co.*, 796
13 N.E.2d 1264 (Ind. Ct. App. 2003).¹

14 **Q8. Have there been changes in NIPSCO's tariff since NIPSCO's last rate case?**

15 A8. Yes. Various changes have been made to NIPSCO's electric tariff over the last 20 years.
16 For example, additional provisions have been added to implement various adjustments in
17 accordance with tracking mechanisms approved by the Commission, including the

¹ The Settlement Agreement approved by the Commission in Cause No. 41746 also provides for certain customer bill credits that have continued beyond the initial 49 month term of the settlement but will terminate when the Commission enters a basic rate order that approves revised NIPSCO electric rates.

1 Environmental Expense Recovery Mechanism ("EERM") and Environmental Cost
2 Recovery Mechanism ("ECRM").

3 **Q9. Please describe the scope of the tariff revisions proposed by NIPSCO in this**
4 **proceeding.**

5 A9. As discussed in more detail by NIPSCO Witnesses Curt A. Westerhausen and Robert D.
6 Greneman, rather than making minor revisions to the current tariff, which has evolved in
7 a piecemeal fashion over the past two decades, NIPSCO chose to substantially revise its
8 tariff reflecting a complete assessment of ratemaking principles, cost of service and bill
9 impacts.

10 **III. REVENUE ADJUSTMENTS TO TEST YEAR**

11 **Q10. Have you reviewed the testimony of NIPSCO Witness Linda E. Miller?**

12 A10. Yes. I will discuss the following five adjustments to test year revenues reflected in
13 Petitioner's Exhibit LEM-2 (Revised) sponsored by Ms. Miller: (1) an increase in
14 NIPSCO's test year revenue to reflect the fact that certain large industrial customers were
15 receiving discounts from tariff rates under special contracts during the test year; (2) a
16 reduction in NIPSCO's test year revenue for certain customers that had consumption
17 greater than the level that will be available to them in the future; (3) a reduction in
18 NIPSCO's test year revenue to eliminate off-system sales margins; (4) a reduction in
19 NIPSCO's test year revenue to eliminate the net proceeds from the sale of emissions

1 allowances; and (5) a reduction in NIPSCO's test year revenue to eliminate non-firm
2 transmission revenues.

3 **Q11. Please explain the basis for Adjustment REV-3 on Petitioner's Exhibit LEM-2.**

4 A11. Adjustment REV-3 on Petitioner's Exhibit LEM-2 is designed to increase NIPSCO's test
5 year revenue by approximately \$80 million to reflect the difference between current tariff
6 rates and the discounted rates currently in place for certain large industrial customers
7 pursuant to special contracts. All of these special contracts have been approved by the
8 Commission over the past few years and some of these special contracts have already
9 expired. The adjustment is primarily related to contracts that have either already expired
10 or are set to expire six months following the implementation of the new basic rates and
11 charges approved in this proceeding in accordance with either the terms of the
12 Commission Orders approving the contracts or the terms of the contracts themselves.
13 NIPSCO has not made an adjustment to its revenue requirement to attempt to recover the
14 difference between the special contract rates and its proposed tariff rates for the six month
15 period between approval of new basic rates and charges and the expiration of the special
16 contracts. Therefore, NIPSCO has imputed revenues for these customers as a proforma
17 adjustment to test year operating revenues.

18 **Q12. Does NIPSCO anticipate that the expiring special contracts will be replaced by new**
19 **special contracts?**

1 A12. No. NIPSCO's cost allocation and rate design in this proceeding are more reflective of
2 the actual cost to serve these customers. This better alignment of rates should eliminate
3 the need for special contract rates for these customers.

4 **Q13. Please explain the basis for Adjustment REV-6 on Petitioner's Exhibit LEM-2.**

5 A13. Adjustment REV-6 on Petitioner's Exhibit LEM-2 reduces operating revenues for a group
6 of customers that operate under contract rates that limit usage periods. During the test
7 year, these customers requested variances, which NIPSCO granted, from the special
8 contract requirements. NIPSCO has removed \$804,136 from test year revenues because
9 these variances were unusual and are not expected to be permitted in the future.
10 NIPSCO's proposed tariff provisions in this proceeding that would be applicable for these
11 customers or similar customers prescribes a better solution to meet their needs.

12 **Q14. Please explain the basis for Adjustment REV-8 on Petitioner's Exhibit LEM-2.**

13 A14. Adjustment REV-8 on Petitioner's Exhibit LEM-2 reduces operating revenues to
14 eliminate off-system sales revenues. During the test year, NIPSCO had off-system sales
15 margins of \$29.1 million. NIPSCO is proposing an adjustment to remove both the
16 revenues and associated expenses (FP-5 on Petitioner's Exhibit LEM-2) from the test
17 year operating results because NIPSCO is proposing that 100% of future off-system sales
18 margins up to \$15 million annually will be passed back to the ratepayers through the
19 proposed RA mechanism. If NIPSCO's off-system sales margins exceed \$15 million in

1 any given year, NIPSCO proposes to pass back 80% of any additional sales margins to its
2 retail customers.

3 **Q15. How did NIPSCO select \$15 million as the dividing line between 100% pass-through**
4 **and 80% pass-through of off-system sales margins to retail customers?**

5 A15. The highest level of margins from off-system sales during the period 2002 through 2006
6 was \$15 million. Off-system sales margins during that period were \$9.7 million in 2002,
7 \$13.8 million in 2003, \$8.7 million in 2004, \$15.4 million in 2005, and \$14.4 million in
8 2006. During 2006 and 2007, NIPSCO relied upon block purchases to meet capacity
9 requirements set by the North American Electric Reliability Corporation
10 ("NERC")/ReliabilityFirst Corporation. NIPSCO purchased blocks of power sufficient to
11 meet a percentage of its expected peak demand during a period, which provided an
12 opportunity for higher off-system sales during non-peak periods. The reasonableness of
13 this method as a way of meeting customer reliability needs was at issue in Cause No.
14 38706-FAC71-S1, wherein NIPSCO agreed to refund \$33 million and also agreed to an
15 ongoing benchmark limiting NIPSCO's ability to recover purchased power costs. These
16 requirements were approved in the Commission's January 30, 2008 Order approving the
17 Stipulation and Agreement in Cause No. 38706-FAC71-S1 ("FAC71-S1 Settlement").
18 Based upon the Commission's approval of the FAC71-S1 Settlement and ongoing
19 discussions with stakeholders, NIPSCO has modified its purchased power practices by
20 acquiring capacity reserves and substantially decreasing block purchases.

1 **Q16. How did NIPSCO select 80% as the appropriate pass-through percentage?**

2 A16. The 80% pass-through percentage is a fair sharing of risk and benefits with customers.
3 By example, if NIPSCO makes \$30 million in off-system sales margin in a given year,
4 under this proposal, NIPSCO's customers would receive \$27 million as a credit in the RA
5 mechanism (100% x \$15 million + 80% of the next \$15 million) which is 90% of the
6 total off-system sales margin). In my opinion, \$30 million would be on the high side of
7 potential future off-system sales.

8 **Q17. Please explain the basis for Adjustment REV-9 on Petitioner's Exhibit LEM-2.**

9 A17. Adjustment REV-9 on Petitioner's Exhibit LEM-2 reduces operating revenues generated
10 through the sales of emission allowances. During 2007, NIPSCO had net proceeds from
11 the sale of emission allowances totaling approximately \$12 million. As further explained
12 by NIPSCO Witness Philip W. Pack, NIPSCO is proposing to revise its EERM to allow
13 NIPSCO to recover the cost of any emission allowance purchases. To promote
14 symmetry, NIPSCO proposes to use the EERM to pass-through as a credit the net
15 proceeds from any future sales of emission allowances.

16 **Q18. Please explain the basis for Adjustment REV-10 on Petitioner's Exhibit LEM-2.**

17 A18. Adjustment REV-10 on Petitioner's Exhibit LEM-2 reduces operating revenues by \$4.7
18 million. This reduction removes non-firm transmission revenues received from the
19 Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") under
20 Schedules 1, 2, 7 and 8. NIPSCO proposes to pass back 100 percent of these net

1 revenues through the RA mechanism. This is appropriate because an ongoing level of
2 transmission revenues cannot be forecasted with any degree of reliability.

3 **IV. RATE POLICY**

4 **Q19. What are the policy objectives that NIPSCO established for this proceeding?**

5 A19. NIPSCO had three overall policy objectives in the development of the rates proposed in
6 this proceeding: (1) the charge for any service rendered is reasonable and just; (2) to the
7 extent possible, the rates should be easy to understand and administer; and (3) the final
8 rates need to consider broader public policy objectives.

9 **Q20. Please further explain the policy objective that rates are just and reasonable.**

10 A20. Reasonableness is a bit of a subjective term, but there are two underlying goals: (1) an
11 appropriate balance between the desire of customers for reasonable rates and NIPSCO's
12 responsibility to its shareholders to design rates that give the Company an opportunity to
13 earn a reasonable return on its investment, which ultimately is also in the customer's best
14 interest; and (2) a reasonable level of equity between customer classes in the final rate
15 design.

16 Obtaining a fair return for investors, in turn, requires that rates be designed based on an
17 appropriate revenue requirement level and that the rate structure provide NIPSCO with a
18 reasonable opportunity to recover that revenue requirement. As discussed by NIPSCO
19 Witness Paul R. Moul, a fair return is critical to NIPSCO's ability to acquire the capital
20 necessary to continue to provide safe and reliable electric service to our customers. One

1 of the biggest challenges in any rate proceeding is balancing equity between customer
2 classes. This is a substantial challenge for NIPSCO in this proceeding. This is the first
3 time in over 20 years that the revenue allocation, implicit in NIPSCO's rates, has been
4 examined in detail. Additionally, NIPSCO's industrial customers represent an unusually
5 high percentage of annual load when compared to other utilities, accounting for more
6 than 50% of annual energy usage on NIPSCO's system. Many of these industrial
7 customers compete in the world marketplace and have options as to where they will
8 produce their products. Within the last 9 months, at least two industrial customers in
9 NIPSCO's territory, Union Tank and Monaco Coach, have announced that they are either
10 closing or substantially reducing production. On the other hand, NIPSCO is well aware
11 of the challenges facing our residential customers that have had to sustain increases in
12 other energy costs such as gasoline and natural gas. NIPSCO's proposed cost allocation
13 and rate design takes into consideration the characteristics of all customer classes.

14 NIPSCO is also addressing in its proposed rate design the difference between "peak" and
15 "off-peak" usage. The advent of the Midwest ISO marketplace has provided much
16 clearer signals on the relative value of electricity for all hours. It is clear from reviewing
17 the Midwest ISO's Locational Marginal Prices ("LMPs") that there is a significant value
18 difference between peak hours in the summer and all other hours for the balance of the
19 year. The simple average LMP price at NIPSCO's load node of peak hours in the
20 summer was \$72.75 as contrasted with an average price for all other hours for the balance
21 of the year at the same load node of \$47.16. This LMP differential reflects the fact that

1 the Midwest ISO is dispatching more costly units as demand rises. NIPSCO believes that
2 its rate design policy should provide more encouragement for customers to move from
3 peak hours to off-peak hours. This is a benefit to all customers in three ways: (1)
4 NIPSCO can reduce production from less efficient units; (2) NIPSCO can reduce
5 purchases from the market that by design reflect the dispatch of higher cost units across
6 the Midwest ISO's footprint as demand rises; and /or (3) NIPSCO can make off-system
7 sales into the Midwest ISO marketplace at the LMP (with the vast majority of these off-
8 system sales margins proposed to be passed back to customers through the RA
9 mechanism).

10 **Q21. Please describe what you mean when you say rates should be easy to understand**
11 **and administer.**

12 A21. It is NIPSCO's belief that all customers want safe and reliable service priced at rates that
13 are easy to understand. We believe our customers are not served well by a complicated
14 tariff that is difficult to understand or complex tariff options that require specialists to
15 evaluate the nuances in detail to find the correct rate for their business. To promote rates
16 that are easy to understand and administer, NIPSCO proposes to reduce the number of
17 rate schedules in its proposed tariff. For example, NIPSCO has reduced the number of
18 Street Lighting rate schedules from 21 to 1.

19 **Q22. Please describe, generally, the notion of offering rates that consider broader public**
20 **policy objectives.**

1 A22. In 2006, the State of Indiana through the Indiana Office of Energy & Defense
2 Development established the Hoosier Homegrown Energy Strategic Plan that encourages
3 energy efficiency investments. This Commission has also conducted hearings on energy
4 efficiency through its investigation of demand side management programs in Cause No.
5 42693. NIPSCO has considered these public policy objectives in the development of its
6 proposed rates in this proceeding and will also do so in a separate case to be filed in the
7 near future that will seek approval of various Demand Side Management ("DSM")
8 programs. This objective does not conflict in any significant way with the other two
9 objectives. These public policy objectives are consistent with revenue allocations that
10 send customers accurate price signals about the cost implications of their consumption
11 decisions, both in terms of revenue allocation among customer classes and rate design.

12 **Q23. Is the Cost of Service Study presented by Mr. Greneman consistent with the**
13 **objectives you describe above?**

14 A23. Yes.

15 **V. KEY RATE DEVELOPMENT DECISIONS**

16 **Q24. Please identify key rate development decisions made by NIPSCO and their**
17 **relationship to the objectives described above.**

18 A24. NIPSCO made a number of decisions in this proceeding to reach the objectives identified
19 above: (1) production costs are allocated based upon 4 Coincident Peaks ("4CP"); (2)
20 fuel costs are removed from base rates to permit recovery of all fuel costs in the FAC; (3)

1 declining block rates are eliminated; (4) certain billing determinants for demand charges
2 have been developed to recognize the difference between peak and off-peak; (5) rates are
3 constructed that encourage lowering peak demand (Rates 526 and 527); (6) the use of
4 Interval Demand Recording ("IDR") meters will be increased for customers served under
5 Rates 523 and 533; (7) interruptible service is continued and expanded; (8) the total
6 number of rate schedules is reduced and the service offerings are simplified so that
7 customers and stakeholders will better understand the options available; (9) the customer
8 charges are increased to better reflect the cost to serve; (10) a new structure has been
9 developed for the Economic Development Rider; and (11) NIPSCO's rate design is
10 adjusted to provide a measured progress toward full cost based rates for certain customer
11 classes in order to avoid rate shock.

12 **Q25. Why did NIPSCO use a 4CP allocation for production costs?**

13 A25. During 2007, NIPSCO's 200 highest demand hours occurred during the four summer
14 months of June through September. In my opinion, the 4CP cost allocation method
15 provides the best alignment between cost causation and rate design for NIPSCO's load
16 profile, as more thoroughly described by Mr. Greneman.

17 **Q26. Please explain in more detail why NIPSCO is proposing to remove all fuel costs**
18 **from its basic rates and instead recover them through the FAC.**

19 A26. To explain why NIPSCO is removing fuel-related costs from its basic rates, I need to
20 briefly recap the evolution of energy markets in the United States. For many years,

1 utilities have forecasted their native load requirements and through economic dispatch
2 principles, determined which of their generating units to dispatch and in what order they
3 would be dispatched. The cost of fuel for this internal generation was recognized in the
4 ratemaking process. Beginning in the early 1970s, changes in the cost of fuel for this
5 internal generation was recovered through FAC proceedings. Electric utilities then
6 became significantly more interconnected and entered into contracts for purchased power,
7 which allowed utilities to decide whether it was more economical to purchase power from
8 a neighboring utility than to dispatch one of its internal generating units to meet its retail
9 load. This Commission has repeatedly encouraged electric utilities to purchase power
10 from neighboring utilities when such power was less expensive than that of the utility's
11 own internal generating units.² In order to encourage this practice and provide customers
12 with the benefit of less expensive resources, the cost of this purchased power was
13 recoverable in the utility's FAC proceedings. NIPSCO is now proposing to remove all
14 fuel costs, including purchased power costs, from its base rates for two reasons: (1) fuel is
15 a variable cost by nature and should not be collected in a fixed component on the bill; and
16 (2) as discussed above, one of NIPSCO's objectives is to simplify its tariff structure and
17 having all fuel costs in one place does simplify the process for customers. In addition,
18 NIPSCO is proposing to remove purchased power and related Midwest ISO costs from

² *Northern Indiana Pub. Serv. Co.*, Cause No. 37343 (IURC 12/27/1983), pp. 4-5. (The Commission found that "it is imperative that [NIPSCO]...commence a program directed toward reducing fuel costs by supplementing internal coal generation of electricity with the purchase of less expensive supplies of electricity from neighboring utilities whenever operating conditions will permit this without adversely affecting the reliability of electrical services.")

1 the FAC and recover these costs through the RA mechanism. NIPSCO Witnesses Curtis
2 L. Crum and Ms. Miller more fully describe this proposal.

3 If the Commission does not accept NIPSCO's proposal and determines that fuel costs
4 (which have been excluded in NIPSCO's rate design) should be included in basic rates, a
5 further adjustment would be necessary in this proceeding to reflect an appropriate level of
6 fuel in basic rates.

7 **Q27. Please explain why NIPSCO has eliminated declining block rates?**

8 A27. Declining block rates cause the per unit cost of energy to decrease as a customer increases
9 its consumption of electricity. NIPSCO believes this rate structure encourages customers
10 to increase energy usage. Given current policies in favor of promoting energy efficiency,
11 NIPSCO proposes to eliminate declining block rates.

12 **Q28. Please explain NIPSCO's rationale for the billing determinants for demand charges**
13 **used in Rates 533 and 534.**

14 A28. In light of public policy objectives and the goal of providing more cost-reflective price
15 signals within classes, NIPSCO is seeking to create greater awareness of seasonal peak
16 versus off-peak usage in the rates proposed in this proceeding. NIPSCO is proposing that
17 the billing determinants for Rates 533 and 534 be set at the higher of 90% of peak usage,
18 defined as the eight-hour period from 11 AM to 7 PM, Monday through Friday, excluding
19 holidays, during the four summer months of June through September, or 80% of all other
20 hours. The billing determinants for a given month will be the highest of the previous 24

1 months using the rule described above. NIPSCO chose a 90% threshold, instead of
2 100%, to avoid overly penalizing a customer which may have had just a handful of high
3 hours during that period. Using 80% of the off-peak period clearly encourages customers
4 to move higher demand into off-peak hours. This billing determinant approach is also
5 consistent with the use of 4CP for allocating production costs.

6 **Q29. Please explain the nature of Rates 526 and 527 and NIPSCO's rate design for those**
7 **rates?**

8 A29. Rates 526 and 527, like the billing determinants rules described above, are established to
9 encourage Off-Peak usage.

10 Rate 526 is specifically identified as Off-Peak Service. This Rate encourages Off-Peak
11 service by setting Billing Demand equal to either 100% of On-Peak hours for the past 12
12 months or 50% of Off-Peak hours for the past 24 months. On-Peak hours for Rate 526
13 are defined as 11 AM to 7 PM from April 1 through September 30 and 1 PM to 9 PM
14 from October 1 to March 31, excluding weekends and holidays. Customers with high
15 load during On-Peak hours would pay more on this Rate than under Rate 533 because
16 under Rate 533 only 90% of Peak is used to determine Billing Demand, rather than 100%.
17 By contrast, a Customer whose demand could be migrated to off-peak hours would be
18 encouraged to do so because their Billing Demand would be set at 50%, as compared
19 80% under Rate 533.

1 Rate 527 offers lower costs to any customer willing to limit operation during peak hours
2 to two out of five business days. This clearly encourages customers to move demand to
3 off-peak periods, which in turn benefits all customers by more efficiently using
4 NIPSCO's system and reducing the need for additional capacity. NIPSCO expects that
5 some customers would be at the beginning of the week (Monday and Tuesday) and others
6 at the end of the week (Thursday and Friday), further diversifying NIPSCO's demand
7 requirements. NIPSCO has included specific provisions for situations when these
8 customers need additional power during periods outside of the hours provided in the Rate.

9 Mr. Greneman discusses the specifics of this rate design and Mr. Westerhausen discusses
10 the specific tariff rules proposed to implement these changes.

11 **Q30. Why does NIPSCO reserve the right to move a customer to Rate 533 or 534 who**
12 **fails to manage its load within the requirements of certain of the rate schedules?**

13 A30. Some of NIPSCO's proposed rate schedules, including Rates 526 and 527, provide lower
14 rates to customers that manage their load moving demand into Off-Peak periods. For
15 example, Rate 527 is designed to encourage customers to move load to off-peak hours.
16 These lower rates are attributable to costs NIPSCO avoids because of this load shift.
17 Customers who fail to manage their load within the requirements of the applicable Rate
18 Schedule are taking the lower rates without reducing the costs that make those lower rates
19 possible. This unfairly shifts costs to either NIPSCO's other customers or its
20 shareholders.

1 **Q31. Please explain why NIPSCO is proposing to increase the number of IDR meters?**

2 A31. NIPSCO is proposing to add additional IDR meters for our medium and large non-
3 residential customers (Rates 523 and 533) so that the nature of load differences among
4 these customers can be better understood. NIPSCO expects to use this data in the future
5 for a number of purposes, including: (1) better allocation of production costs to these
6 classes; (2) better allocation of energy costs to these classes; (3) development of riders for
7 these rate schedules to provide incentives for lower peak usage; and (4) more accurate
8 knowledge of overall system operations. As discussed further by NIPSCO Witness
9 Timothy A. Dehring, NIPSCO will be establishing processes to read and record the
10 information provided by the meters. This information also will be useful in evaluating
11 the potential value of extending these devices to smaller customer classes.

12 **Q32. Why has NIPSCO limited the applicability of Rate 523?**

13 A32. Rate 523 was designed for customers on the Company's distribution system, many of
14 whom do not currently have IDR meters and therefore the billing determinants are
15 simplified and not appropriate for larger customers.

16 **Q33. Please explain Rate 536 for interruptible service and the rationale for its design and**
17 **the expected volumes used to create the rate schedule.**

18 A33. Interruptible load that conforms to the Midwest ISO interruption requirements will
19 benefit all customers by allowing NIPSCO to avoid building new facilities or paying for
20 capacity to meet reliability standards. NIPSCO's Rate 536 conforms to the Midwest ISO

1 interruption requirements. NIPSCO has allocated only 50% of the capacity costs to this
2 rate schedule because of its ability to interrupt service on short notice.

3 NIPSCO has evaluated the load characteristics of the customers eligible for this tariff to
4 determine the billing determinants used in the proposed rates. This determination was
5 based on those customers that (a) currently are on interruptible service or (b) have self-
6 generation options.

7 **Q34. Why is NIPSCO limiting participation in Rate 536 to 250 MW?**

8 A34. The counterpart to Rate 536 in NIPSCO's current rates and charges (Rate 836) limits the
9 rate's availability to 110 MW. NIPSCO has estimated that the total load of current
10 customers who would benefit from this Rate is 250 MW. NIPSCO is proposing to
11 increase its amount of interruptible service to meet this projected demand, which more
12 than doubles the currently availability, and consequently, NIPSCO seeks to limit the
13 availability of this Rate to 250 MW. Additionally, this limitation serves to protect against
14 the risk associated with earnings erosion if more customers migrate to this rate than what
15 NIPSCO assumed in its Cost of Service Study. Mr. Greneman further explains the
16 implications of the Cost of Service Study.

17 **Q35. Please explain why NIPSCO is reducing the number of customer Rates.**

18 A35. NIPSCO is proposing to reduce the number of customer Rates from 42 to 13.
19 Determining the appropriate number of customer rates is a balance between seeking
20 equitable cost allocation among customers with different characteristics and the

1 simplicity and administrative feasibility of fewer rate offerings with some embedded
2 riders. NIPSCO has decided to move in the direction of simplicity and administrative
3 feasibility in this proceeding. While many of NIPSCO's customers have diverse usage
4 characteristics, NIPSCO's proposed rate restructuring is now able to better align customer
5 load profile with the Company's underlying cost structure.

6 **Q36. Please explain the rationale for NIPSCO's Economic Development Rider.**

7 A36. It is in the best interest of NIPSCO and its customers that NIPSCO promote its service
8 territory as a viable location for new businesses. Competition has become strong within
9 the United States and globally for business expansions. It takes a concerted effort on the
10 part of the state, local communities and utilities to create the best chance to bring new
11 business to the territory. Benefits to NIPSCO customers include an increased tax base
12 from the investment and potential new employment with related income tax, sales tax and
13 property tax benefits.

14 NIPSCO is proposing discounts to non-fuel rates to avoid shifting the burden to other
15 customers. NIPSCO will also assure that the rate will be above the incremental cost to
16 provide service to a new customer. NIPSCO seeks the ability to discount the non-fuel
17 rate for up to 5 years and by up to 50% in the first year declining to 10% by year 5.
18 NIPSCO will evaluate a number of key variables prior to offering the discount, including
19 whether the facility is located in a "brownfield" area. By brownfield, I mean areas of
20 NIPSCO's territory where existing transmission and distribution facilities are not at

1 capacity and limited new facilities would be required for new business. NIPSCO has a
2 number of areas where existing transmission and distribution facilities are not at capacity.
3 Locating new facilities in those areas can be done at the lowest incremental cost.
4 NIPSCO will consider additional criteria in determining the appropriate discounts as
5 defined in the proposed tariff as discussed by Mr. Westerhausen.

6 **Q37. Is NIPSCO proposing to change its new business policy in this proceeding?**

7 A37. Yes.

8 **Q38. Please explain the change and rationale?**

9 A38. NIPSCO is seeking to move away from the simple calculation of 2.5 times revenue to
10 define the appropriate investment level that NIPSCO should make for new business.
11 Revenue is not a good proxy for contribution to a fixed asset business, although I admit it
12 is a simple calculation. NIPSCO is proposing to consider the non-fuel margin and
13 expected non-fuel revenue to determine an appropriate investment level based upon net
14 present value of the revenue stream. Using this methodology, NIPSCO proposes that the
15 appropriate investment level be \$3,500 per residential customer. Using the existing 2.5
16 times revenue produces approximately \$2,500. This change will assist in encouraging
17 housing growth in NIPSCO's service territory during a period that can certainly use
18 additional encouragement.

19 **Q39. Please explain why NIPSCO is proposing modifications of the cost-based revenue**
20 **allocations and the impact of those modifications?**

1 A39. Upon completion of the class embedded cost study, it was apparent that a substantial cost
2 shift was occurring among the three major customer classes. Because existing rates date
3 back to the early 1980's, there are many possible explanations for the changes, including
4 fundamental shifts in demand in the commercial class that has moved from smaller units
5 to big box operations during this period, and changing residential usage patterns with the
6 major changes in electrical appliances over this period. NIPSCO suspects, but cannot
7 confirm, that the current tariff reflects some social engineering of the rates to shift costs
8 from residential to commercial and industrial customers. Whatever the reason, NIPSCO
9 seeks to move toward rates that rely on cost-based allocations with limited social
10 adjustments. However, moving to cost-based allocations in one step (after 20 years)
11 would result in a 31.4% increase in basic rates for residential customers.

12 NIPSCO is therefore proposing a 25 percent decrease in the existing subsidy in this
13 proceeding, yielding an average 16.73% increase in basic rates to residential customers.

14 **Q40. Are you familiar with NIPSCO's load research study?**

15 A40. Yes, I am. To improve the allocation of demand costs, NIPSCO conducted additional
16 load research on our customer segments that have lower usage levels, specifically small
17 commercial and residential customers. It should be noted that NIPSCO has detailed
18 meter information (hourly or at least periodic demand) on over 50% of our annual volume
19 including all large industrial customers. The additional load research was performed to
20 better understand the differences between small commercial and residential customers

1 only. The results were provided to Mr. Greneman for his use in allocating demand costs
2 between these classes.

3 **Q41. Are you familiar with NIPSCO's proposal to treat its electric utility business as**
4 **100% jurisdictional?**

5 A41. Yes, I am.

6 **Q42. Please explain the rationale for this proposal.**

7 A42. NIPSCO's system is designed to serve jurisdictional customers. As the Midwest ISO
8 marketplace develops, transmission services, energy sales, and ancillary services can be
9 purchased from the Midwest ISO. In the past, NIPSCO treated a small amount of its
10 business as non-jurisdictional because it provides a small amount of FERC-regulated
11 wholesale service to the City of Argos under a long-term contract, FERC-regulated
12 ancillary services to Indiana Municipal Power Agency ("IMPA") and FERC-regulated
13 transmission service to Wabash Valley Power Association, Inc. ("WVPA"). Given the
14 small size and incidental amount of the non-jurisdictional business, NIPSCO believes its
15 business should be treated as 100% jurisdictional and that revenues from these incidental
16 wholesale ancillary services and transmission services should be credited to retail
17 customers as described in greater detail by Mr. Greneman. NIPSCO will treat these
18 revenues as jurisdictional for purposes of NIPSCO's calculation of compliance with the
19 earnings test in its FAC.

20 **VI. THE RA MECHANISM**

1 **Q43. What costs and offsetting revenues is NIPSCO seeking to recover through the**
2 **proposed RA mechanism?**

3 A43. NIPSCO is seeking recovery of all purchased power costs, capacity costs, and all non-
4 FAC MISO costs offset by non-FAC MISO credits and off-system sales margins as
5 detailed by Mr. Crum.

6 **Q44. Please describe why NIPSCO is seeking to recover these costs through the RA.**

7 A44. As Mr. Crum describes, these costs are necessary components to the provision of reliable
8 service. NIPSCO believes that because of the variable nature of these costs, recovery
9 through a tracker is more appropriate than including it as an operating expense when
10 establishing NIPSCO's fair rate of return. These costs will be reviewable on a quarterly
11 basis in the RA mechanism. Including these costs in a tracker assures that NIPSCO will
12 recover no more and no less than the actual costs incurred in connection with these
13 reliability requirements, provides ongoing scrutiny of these costs by the Commission and
14 provides a means to pass through offsetting revenues and credits to retail customers. For
15 example, capacity costs will be reduced because the Sugar Creek Facility dispatches into
16 the Midwest ISO. Recovering these costs in the RA ensures that customers receive the
17 benefits of decreases in any of the costs or increases in the credits described above. It
18 also provides more accurate price signals to our customers. I would also note that
19 inclusion of purchased power costs in the RA is consistent with the FAC71-S1 Settlement
20 Agreement, which provided for recovery of these costs through a Section 42(a)
21 mechanism.

1 NIPSCO proposes to offset these costs by passing back off-system sales margins, as
2 described above, through this mechanism. Many off-system sales are now made the same
3 way energy is purchased – through the Midwest ISO. Accordingly, it is appropriate to use
4 the RA mechanism to pass these margins back to customers.

5 **VII. SIMPLIFICATION OF AND REDUCTION IN THE NUMBER OF RATE**
6 **SCHEDULES**

7 **Q45. Please provide an overview of NIPSCO's efforts to simplify and reduce its number**
8 **of rate schedules.**

9 A45. Currently, NIPSCO has 42 Rate Schedules and is proposing a reduction to 13 rate
10 schedules in this proceeding. NIPSCO continues to provide rate flexibility. For example,
11 Rate 534 (customers over 10 MW) is primarily targeted for transmission level customers
12 but the rate design is set based upon delivery at the primary distribution system. Credit is
13 provided to customers who take service at the transmission level in Rate 534. This rate
14 design allows all customers with load over 10 MW to qualify for the service, not just
15 those on the transmission system. NIPSCO is also seeking to simplify its tariff structure
16 by moving elements of the rate schedules that are common into the general rules and
17 regulations, thereby limiting the rate schedules to the service criteria and pricing. Mr.
18 Westerhausen provides a broader discussion of NIPSCO's rate schedules, riders and
19 rules.

20 **Q46. Please describe the reclassification process used in defining the tariff categories.**

1 A46. Most residential customers will map easily from Rate 811 to the new Rate 511 schedules.

2 NIPSCO is converting two additional residential rates into riders for Rate 511. There are
3 a number of schedules in the commercial/small industrial classes that will be collapsed
4 into just three (3) rate schedules (Rates 521, 523 and 533). Rate 521 is designed for small
5 commercial customers that do not have demand meters. These customers are not likely to
6 have as much energy acquisition sophistication as larger customers. The rate structure is
7 similar to the residential rates with a customer charge and a volumetric per kWh charge.

8 Rate 523 contains a broad grouping of customers, estimated at 11,500, that receive power
9 from the distribution system. This is the first rate schedule that provides a demand
10 charge. Customers were mapped into this rate schedule from Rates 821, 823 and 824
11 based upon a combination of the assets used to serve these customers, demand data from
12 those customers with permanent demand meters and sampling demand meters. This is a
13 difficult grouping because of the variety of loads within this class. In recognition of this
14 difficulty, NIPSCO is planning to expand the use of IDR meters within this group.
15 NIPSCO is also providing a number of riders that can be used to better fit customer needs
16 in this Rate.

17 Rate 533 contains a smaller group of customers, estimated at 900 plus, that take service at
18 the distribution and transmission levels. These customers, by and large, have had demand
19 meters for some time. Customers were mapped into this rate schedule from 817, 820,
20 821, 823, 824, 826, 832 and 833 based upon a combination of the assets used to serve

1 these customers and demand data from the existing demand meters. NIPSCO will be
2 replacing existing Demand Indicating meters with IDR meters, in this group for better
3 understanding of load characteristics.

4 **Q47. Several of the rate schedules require a separate contract with the customer. Is**
5 **NIPSCO proposing to negotiate a contract unique to each customer?**

6 A47. No. While certain terms in the contracts will be unique to the customer, NIPSCO will
7 develop standard forms consistent with the tariff. Individual contracts are necessary to
8 identify customer specific data such as usage history.

9 **Q48. Please explain Rider 575?**

10 A48. NIPSCO's current tariff includes three (3) separate space heating rates. Consistent with
11 NIPSCO's effort to simplify its tariff, the three (3) existing rate schedules have been
12 transitioned to one rider, Rider 575. This rider increases the threshold for the discount
13 applicable to the Energy Charge for residential customers to 700 kWh during October
14 through April based upon a review of space heating customer usage.

15 **VIII. DSM PROGRAMS**

16 **Q49. Is NIPSCO proposing specific DSM programs in this proceeding?**

17 A49. No. After consideration of the complexity of filing its first base rate case in over 20
18 years, NIPSCO decided that its DSM programs and related concepts should be filed in a
19 separate proceeding. NIPSCO anticipates making this filing in fall 2008, with the hope
20 that approval is received by early 2009 in order to allow for specific programs to be

1 available to customers for the summer of 2009. Given the schedule for this proceeding,
2 an implementation date that early would not be possible if the DSM programs were
3 proposed in the context of this proceeding.

4 **Q50. Is NIPSCO introducing concepts within this proceeding that are consistent with its**
5 **DSM efforts?**

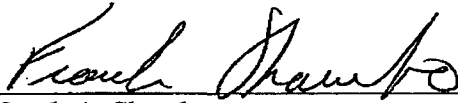
6 A50. Yes. As discussed above, NIPSCO is proposing a number of rate changes to be more
7 consistent with its efforts to expand DSM. Specifically, NIPSCO is removing declining
8 blocks, offering an interruptible rate (Rate 536), offering variations of off-peak rates
9 (Rates 526 and 527) and setting billing determinants for Rates 533 and 534 at 90% of
10 summer peak hours versus 80% of all other hours. Also, as discussed above and by Mr.
11 Dehring, NIPSCO will be introducing IDR meters to a much larger group of customers in
12 an effort to better understand their usage characteristics.

13 **Q51. Does this conclude your prepared direct testimony?**

14 A51. Yes, it does.

VERIFICATION

I, Frank A. Shambo, Vice President, Regulatory and Legislative Affairs for Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.


Frank A. Shambo

Date: December 19, 2008

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED SUPPLEMENTAL DIRECT TESTIMONY

OF

FRANK A. SHAMBO

VICE PRESIDENT, REGULATORY AND LEGISLATIVE AFFAIRS

VERIFIED SUPPLEMENTAL DIRECT TESTIMONY OF FRANK A. SHAMBO

1 **Q1. Please state your name, occupation and business address.**

2 A1. My name is Frank A. Shambo. I am Vice President, Regulatory and Legislative Affairs
3 for Northern Indiana Public Service Company ("NIPSCO"). My business address is 101
4 W. Ohio Street, Indianapolis, Indiana 46204.

5 **Q2. Did you previously submit Prepared Direct Testimony as a part of the Case-In-**
6 **Chief of Petitioner NIPSCO filed with the Commission in this Cause on August 29,**
7 **2008?**

8 A2. Yes. My Prepared Direct Testimony has been marked as Petitioner's Exhibit FAS-1.

9 **Q3. What is the purpose of your Supplemental Direct Testimony?**

10 A3. The purpose of my Supplemental Direct Testimony is to describe the revision to
11 NIPSCO's rate increase proposal to incorporate the effect of the inclusion of the Sugar
12 Creek Generating Facility ("Sugar Creek" or "Sugar Creek Facility") into the Midwest
13 Independent Transmission System Operator, Inc. ("Midwest ISO") and its availability for
14 dispatch into Midwest ISO's markets.

15 **Q4. Please describe the Sugar Creek Facility.**

16 A4. The Sugar Creek Facility is a 535 MW combined cycle combustion turbine generating
17 facility ("CCGT") located near Terre Haute, Indiana. The Sugar Creek Facility was
18 acquired by NIPSCO through the purchase of the equity interests in Sugar Creek Power
19 Company, LLC and the subsequent merger of that company into NIPSCO. NIPSCO

1 acquired the equity interests on May 30, 2008 pursuant to the Commission's Order in
2 Cause No. 43396 dated May 28, 2008 ("CPCN Order") granting NIPSCO a Certificate of
3 Public Convenience and Necessity ("CPCN") for the acquisition and NIPSCO assumed
4 control of the Sugar Creek Facility on that date. The Sugar Creek Facility is capable of
5 connection to either the Midwest ISO or the PJM Interconnection, LLC ("PJM") markets.

6 **Q5. Why did NIPSCO originally propose a two step process to reflect the capital costs**
7 **and operating expenses relating to the Sugar Creek Facility?**

8 A5. NIPSCO's Step Two rate adjustment proposal was necessary to resolve a difference
9 between the time when the Sugar Creek Facility could be reflected in NIPSCO's retail
10 rates and the time NIPSCO agreed to initiate this rate proceeding. Because the Sugar
11 Creek Facility was committed to the PJM market through May 31, 2010, the Commission
12 found that it would not be includible in NIPSCO's rate base until the unit was
13 dispatchable in the Midwest ISO. Therefore, NIPSCO originally proposed the Step Two
14 rate adjustment in its Case-In-Chief filed on August 29, 2008 to incorporate the costs
15 associated with the Sugar Creek Facility once it became dispatched into the Midwest
16 ISO, which was then anticipated to occur after the Commission's issuance of an order in
17 this proceeding.

18 **Q6. Is Step Two of NIPSCO's two-step rate increase proposal as originally proposed by**
19 **NIPSCO still necessary?**

20 A6. No. As I stated in my prefiled direct testimony filed on August 29, 2008, NIPSCO planned
21 to explore any opportunities that may arise to terminate the PJM commitment earlier than

1 May 31, 2010 and to dispatch Sugar Creek into the Midwest ISO markets as soon as
2 possible. As stated in the revised testimony of NIPSCO Witness Bradley K. Sweet,
3 effective December 1, 2008 Sugar Creek is an Internal Designated Network Resource in
4 the Midwest ISO, and it has been offered into the Day Ahead and Real Time Markets in
5 the Midwest ISO since and including December 1, 2008. This means that Sugar Creek
6 (1) is no longer committed to the PJM markets through May 31, 2010, (2) is in-service
7 for the benefit of NIPSCO's ratepayers, (3) may be dispatched by the Midwest ISO
8 towards NIPSCO's daily load, and (4) counts towards NIPSCO's capacity and reliability
9 requirements. The effect of this change is to make the Sugar Creek Facility used and
10 useful for the benefit of NIPSCO's ratepayers as of December 1, 2008. Therefore, the
11 Sugar Creek costs should be reflected in NIPSCO's rates upon the issuance of the
12 Commission's order in this proceeding in which event the Step Two rate adjustment is no
13 longer necessary.

14 **Q7. Is NIPSCO proposing to incorporate Sugar Creek into its rate base immediately for**
15 **purposes of its request for relief in this proceeding?**

16 A7. Yes. Because Step Two is no longer necessary, NIPSCO is revising and supplementing
17 its evidence to reflect the addition of Sugar Creek on December 1, 2008. This change
18 impacts NIPSCO's proposed revenue requirement, its cost of service, and its proposed
19 rates and charges.

20 **Q8. What is the effect of this change on the rate relief requested by NIPSCO?**

1 A8. NIPSCO Witness Linda E. Miller has recalculated the revenue requirement to be
2 \$962,393,192, a 6.78% increase over the revenue requirement proposed for the originally
3 filed Step One. With the inclusion of its revised and supplemental evidence, NIPSCO is
4 now proposing an approximately \$85 million increase in revenues, yielding a 9.78%
5 revenue increase.

6 **Q9. Does NIPSCO still propose to recover deferred depreciation expense and carrying**
7 **costs relating to its investment in Sugar Creek?**

8 A9. Yes. As a result of the Sugar Creek development described above, NIPSCO has filed a
9 *Stipulation and Settlement Agreement* and supporting evidence in Cause No. 43396-S1
10 seeking deferral of such depreciation expense and carrying costs beginning with the
11 December 1, 2008 in-service date for Sugar Creek. NIPSCO is proposing to recover the
12 deferred depreciation expense and carrying costs over a five year period commencing
13 with a Commission Order in this proceeding. After expiration of the five year period,
14 NIPSCO's rates will be adjusted to remove the recovery of such costs. This proposal is
15 consistent with the *Stipulation and Settlement Agreement* in Cause No. 43396-S1, and the
16 Commission's January 30, 2008 Order approving the Stipulation and Agreement in Cause
17 No. 38706-FAC71-S1. NIPSCO is no longer proposing to earn a return on the deferred
18 costs as originally proposed in the Step Two adjustment described in NIPSCO's Case-In-
19 Chief as filed on August 29, 2008.

20 **Q10. Is the recovery of the deferred depreciation expense and carrying costs larger or**
21 **smaller than that originally proposed for Step Two?**

1 A10. It is smaller for two reasons. First, the period of deferral has been reduced to reflect the
2 fact that Sugar Creek is in-service as of December 1, 2008 and deferral will end with the
3 implementation of new rates estimated to be January 1, 2010 compared with the original
4 filing assumed deferral from June 1, 2008 through May 31, 2010 when the facility was
5 planned to enter the Midwest ISO. Second, the deferral of carrying costs are proposed to
6 be based on the value of Sugar Creek less the depreciation expense booked by NIPSCO
7 between the time of purchase and the in-service date of December 1, 2008.

8 **Q11. What is the effect of NIPSCO's ability to include the Sugar Creek facility in its rate**
9 **base as of December 1, 2008, when compared to the revenue requirement that would**
10 **have resulted if the Commission had approved the recovery of deferred depreciation**
11 **and carrying costs as originally proposed?**

12 A11. The effect is a reduction of approximately \$14.9 million, which represents the benefit to
13 customers of NIPSCO's ability to begin dispatching Sugar Creek into the Midwest ISO at an
14 earlier date than originally anticipated. This figure is the difference between the previously
15 requested revenue increase of \$104,706,946 less \$89,752,221, with the latter figure
16 representing the revenue requirement without any adjustment for the Anthem medical
17 expense as discussed by Ms. Miller.

18 **Q12. Does NIPSCO still propose to provide measured progress toward full cost-based**
19 **rates in order to avoid rate shock?**

20 A12. Yes, NIPSCO is still proposing a measured movement toward cost-based rates to mitigate
21 the impact of rate shock. Specifically, the allocation of the revenue requirement provided

1 by Mr. Greneman represents a step toward full cost-based rates from NIPSCO's previous
2 rate design. By instituting a 25% moderation plan the Company's proposal mitigates the
3 effect of taking an otherwise immediate transition to full cost-based rates.

4 **Q13. Please explain NIPSCO's process of instituting this 25% moderation plan.**

5 A13. NIPSCO anticipated that large cost shifts would occur if it made an immediate transition to
6 a fully-allocated revenue requirement. Therefore, NIPSCO requested Mr. Greneman to
7 evaluate the impact of instituting the rate design change without any increase in revenue
8 requirement. This step would highlight to NIPSCO and others the difference associated
9 solely with a rate design that allocated its revenue requirement to its customer classes.
10 The change in rate design alone, without any revenue requirement increase, would result in
11 a 19.6% rate increase to Rate 511 (residential), a 32.6% decrease to Rate 521, a 10.1%
12 decrease to Rate 533, and a 5.3% decrease to customers served under Rate 534.

13 **Q14. Please explain the impact and the 25% moderation plan further.**

14 A14. One of NIPSCO's objectives is to minimize rate shock associated with its proposed rates.
15 NIPSCO balanced the benefits of a rate design that fully allocates the revenue requirement
16 to NIPSCO's customer classes with the need to mitigate rate shock to any specific customer
17 class. When taking into account the requested revenue requirement, there would be a 31.4%
18 increase to Rate 511 customers, a 26.0% decrease to Rate 521, a 1.2% decrease to Rate 533
19 and a 4.8% increase to Rate 534 customers. Taking all of this into consideration, NIPSCO
20 does not believe it is appropriate at this time to allow the effect of a fully-allocated revenue
21 requirement to impact residential customers' bills by 30% or more. As a reflection of its

1 approach to this balance, NIPSCO proposes to mitigate the impact of moving to a fully-
2 allocated revenue requirement by taking measured steps. NIPSCO proposes to reduce the
3 existing residential subsidy by 25 percent in this proceeding, and expects to make further
4 progress towards truly cost-based rates in future rate proceedings.

5 **Q15. Is this the same approach NIPSCO originally proposed in its Case-In-Chief?**

6 A15. The policy goal behind the rate design is the same. As explained by Mr. Greneman,
7 however, the mechanics of the proposed design have been modified. NIPSCO's policy
8 objective is to move toward fully allocated rates for all customer classes, while mitigating
9 the impact of that movement in this case to reduce rate shock. In NIPSCO's original two
10 step approach, the Company proposed a one third movement toward fully cost based rates in
11 the first step, with the increase in the second step being fully allocated across all customer
12 classes without mitigation.

13 Even though the two steps of the proposed increase have been consolidated, NIPSCO's
14 rate design still uses two steps to reach its policy objective. NIPSCO derived allocation
15 factors based on a full allocation of rates. In the first step, NIPSCO isolated the rate
16 impact associated only with shifts in demand and operational characteristics since
17 NIPSCO's rates were last designed by applying those allocation factors assuming no
18 increase in its revenue requirements. Because that impact alone would have increased
19 residential rates by nearly 20%, NIPSCO elected to limit the movement toward full cost
20 allocation of those costs to twenty-five percent. In the second step, the increase in
21 revenue requirements requested in this proceeding was divided among all customer

1 classes using the factors originally derived based on a full allocation of costs without
2 mitigation. The result for Residential customers served under Rate 511 will be an
3 increase of 16.53%, as compared to a total of a 17.53% increase under the two steps
4 originally proposed. While the other portions of the revenue requirement not allocated to
5 Rate 511 are shifted to other customers, it is still less than what would have been
6 maintained under the previous rate design. NIPSCO acknowledges that the selection of a
7 25% moderation plan is somewhat subjective. However, it is a reasonable balance
8 between two competing interests of correcting legacy rate design and mitigating its rate
9 design impacts on customers.

10 **Q16. Is NIPSCO's proposal as reflected in its revised and supplemental evidence in the**
11 **public interest?**

12 A16. Yes. As recognized by the grant of a CPCN through the CPCN Order, the public
13 convenience and necessity were served by NIPSCO's purchase of the Sugar Creek
14 Facility. The Facility's purchase brought necessary capacity and fuel diversity to
15 NIPSCO's generating mix. NIPSCO's 2007 Integrated Resource Plan demonstrated that
16 NIPSCO would need to either acquire or construct additional generation facilities as part
17 of its strategy to meet its capacity requirements. Acquisition of the Sugar Creek Facility
18 resulted from NIPSCO's thorough RFP process designed to identify the most cost
19 effective options to meet its need for additional generation. The Sugar Creek Facility
20 was the most cost effective alternative for NIPSCO to acquire needed capacity. Had
21 NIPSCO constructed an equivalent facility, the cost to ratepayers would have been two to
22 six times what it is with the Sugar Creek Facility and NIPSCO would have been able to


1 capitalize carrying costs on its investment during the construction period through
2 allowance for funds used during construction. Penalizing NIPSCO for acquiring the
3 lowest cost facility, which was temporarily non-dispatchable in the Midwest ISO, would
4 discourage Indiana utilities from exploring such opportunities. This could result in
5 higher prices for Indiana retail customers.

6 **Q17. Does this complete your Supplemental Direct Testimony?**

7 **A17. Yes.**

VERIFICATION

I, Frank A. Shambo, Vice President, Regulatory and Legislative Affairs for Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.


Frank A. Shambo

Date: December 19, 2008